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A THREE MEGAWATT BIOMASS-FIRED COGENERATION PLANT FEASIBILITY STUDY

Prepared for

MONTANA DEPARTMENT of NATURAL RESOURCES and CONSERVATION

A THREE MEGAWATT BIOMASS-FIRED COGENERATION PLANT FEASIBILITY STUDY

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Montana Department of Natural Resources and Conservation
32 South Ewing, Helena, Montana 59620
Biomass Utilization and Cogeneration Program
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1.0 EXECUTIVE SUMMARY

Flodin Lumber and Manufacturing Company presently owns and operates a sawmill near Thompson Falls, Montana, which produces approximately 14 to 17 million board feet of lumber a year. The existing facility consists of two head rigs, planer mill, storage facilities, three dry kilns and a steam boiler plant. The boiler plant consists of two 40-year old wood fired boilers supplying process steam to the kilns. These antiquated boilers have been derated and are due shortly for replacement.

This report investigates the feasibility of replacing these boilers with a larger boiler capable of supplying high pressure steam to a turbine generator in addition to the dry kilns. The resultant power produced and sold to the utility is used to offset the initial capital investment.

The plant size and configuration of the proposed biomass fired cogeneration facility, including detail systems and equipment description, are presented in Section 3.0. The capital costs for the design supply and construction of the plant are itemized in Section 5.0.

The burning of wood waste in a power boiler for the production of steam and power is a proven technology. Due to the relatively small size of the cogeneration facility, the environmental permitting of the plant should be straightforward with no unforseen problems anticipated. Other pertinent planning and implementation considerations for the installation of the plant are described in Section 6.0.

The majority of the wood to be fired will be generated on site at a relatively low price as a byproduct of the sawmill. The remaining fuel supply will be purchased from WI sawmill or other sources of shavings from adjacent mills. A detailed discussion of the wood byproducts and proposed wood handling system is given in Section 2.0.

From the economic analysis performed herein, the installation of the biomass fired boiler and 3 1/2 MW (gross) steam turbine generator facility is an economically attractive and viable investment for Flodin Lumber and Manufacturing Company to consider making. Legislation which encourages cogeneration as a viable option for companies to pursue are explained in Section 4.0.

Since the economic feasibility of the project is predicated on its source of revenue, the sensitivity of changes in the rate of which Montana Power Company (MPC) purchases power from qualifying cogeneration facilities is considered. Based on the long term power purchase schedule presently in effect, the after tax return on investment (ROI) for the cogeneration plant investment is approximately 26 percent.

Currently, MPC is contesting to the Montana Public Service Commission the full avoided cost of \$0.0533/KWH plus capacity payment published in Schedule #LTPP-82. From figure 5-1, if the composite electrical rate is reduced by the Public Service Commission from \$0.0641/KWH to \$0.04/KWH, the ROI is decreased from 26 percent down to 13 percent. Even with this significant reduction in the ROI, an after tax ROI of 13 percent is still within the minimum acceptable rate of return established by Flodin Lumber (i.e. MARR = 12 to 15 percent.)

2.0 FUEL SUPPLY ANALYSIS

To determine the quantity of fuel required, it was first necessary to evaluate the present steam generation capacity and use at Flodin Lumber and Manufacturing Company. The second step was to determine the quantity of steam required for the power generation.

The Flodin Lumber sawmill has two existing 40-year old, 125 horsepower boilers supplying process steam to the kilns. The fuel for these boilers is sawdust and shavings obtained from the sawmill operation. According to the boiler operator, the boiler was originally rated at 125 psig, but has since been derated to 100 psig. The steam pressure ranges from 60 psig, when the kilns are started up, to 90 psig during normal operation. The maximum combined output of both boilers is estimated to be less than 7,000 lbs. per hour. The boiler is normally operated with natural draft only, with the forced draft fans started when necessary. With a steady fuel feed, the operator controls steam flow with manual operation of the inlet and outlet dampers. Flodin management has indicated that under severe conditions the two boilers were not able to handle the existing lumber dry kilns on startup. Under normal operating conditions, one existing boiler can carry the dry kiln load with surplus capacity.

Since the existing boilers would be replaced by the cogeneration facility, the new steam generator will be sized to handle the existing steam requirements in addition to the steam required for electrical power generation. The mass and heat balance for the thermal cycle is depicted on drawing No. 40X3011B-M203 included herein under Section 3.1. The steam generation requirements for the nominal 3000 KW (3500 KW gross output) cogeneration plant are tabulated below:

STEAM USER	SUPERHEATER OUTLET FLOW (600 PSIG, 750°F)
3500 KW Steam Turbine Generator	38,220 lb/hr
Deaerator	3,902 lb/hr
Dry Kilns (average)	2,900 lb/hr
TOTAL	45,022 lb/hr*

The dry kiln flow is an estimated average for year around operation. During startup of the kilns and other intermittent modes of operation where the process steam demand exceeds the average flow, the throttle steam flow to the turbine will be reduced accordingly with an associated reduction in power generation.

In addition to the 3 MW cogeneration plant, this section of the report will consider the availibility and requirements of fuel to support the operation of a 5 MW cogeneration plant. Henceforth, the 3 MW cogeneration plant will be referred to as the base case and the 5 MW cogeneration plant as the alternate case.

*Feedwater flow, as shown on drawing No. M203, is greater than the superheater outlet flow due to blowdown from the boiler drum.

2.1 FUEL AVAILABLE

It was determined that there are four major sources of fuel in the Thompson Falls Area. These are:

1. Flodin Lumber, Thompson Falls
2. WI, Thompson Falls
3. Louisiana Pacific, Trout Creek
4. Purchased hogged dead Lodge Pole Pine

For Flodin Lumber, it was determined that there are two basic operations throughputs from which the potential fuel production quantities should be calculated. The first basis would be to assume 1 1/2 shift per day for a 5 day week using present operating througputs. The second basis is to assume that the planned 21.4% increase in throughput is realized by 1984.

In estimating the fuel available from Flodin, the following material was used:

1. Computer printouts of sales to Louisiana Pacific, Missoula.
2. Quantities estimated by Flodin management.
3. Calculated quantities of fuel burned in the existing boiler plant.
4. An evaluation of the existing mill operations modified by standard "rule of thumb" estimates.

For WI in Thompson Falls, the fuel available was assumed to be equal to that sold to LP, Missoula, plus surplus hogged fuel presently burned in tepee burners. The fuel availability numbers were modified to include a steady operation at one shift per day for a five day week.

For LP, the production from Trout Creek was estimated by Trout Creek personnel.

For the purchased hogged dead Lodgepole pine, it was assumed that a contractor would deliver the fuel directed to the steam generation facility. Data from other dead Lodgepole pine operations indicate that the fuel will arrive at the plant site with an average of 33 percent H_2O content. Operations at LaGrande, Oregon show a 25 percent moisture content in chips derived from dead Lodgepole pine. No purchased hogged Lodgepole pine is used in the base because of the close proximity of the shavings available from WI, Thompson Falls. For the alternate case, the dead Lodge-pine is used for that quantity of fuel required above that supplied by Flodin and WI shavings. Assuming a potential for plant interruptions at WI and LP, the purchased hogged Lodgepole pine is used for the balance of the fuel requirement. Under almost any circumstance more fuel is available than is required for the 5 MW alternate case.

The following is a tabulation of the estimated quantities of fuel available from each source: (tabulated in dry tons per year, moisture content and wet tons per year).

Flodin Base Case (based on 1 1/2 shift per day per 5 day week):

	Tons/Yr Bone Dry Basis	%H_2O Wet Basis	Tons/Yr Wet Basis
Shavings	4650	8.4	5076
Sawdust	4650	40.0	7750
Hogged Fuel	18095	45.0	32900

Flodin Alternate Case (based on 1 1/2 shift per day per 5 day week)

Shavings	5731	8.4	6257
Sawdust	5800	40.0	9667
Hogged Fuel	21973	45.0	39951

WI, Thompson Falls (based on 1 shift per day per 5 day week)

Shavings	4567	13.9	5304
Hogged Fuel	29304	45.0	53280

Louisiana Pacific, Trout Creek Mill (based on 1 shift per day per 5 day week):

Shavings	8064	15.0	9487
Sawdust	3360	50.0	6720
Hogged Fuel	14784	55.0	32853

Purchased Fuel (Hogged Dead Lodgepole pine):

Hogged Fuel	As Required	33.0	As Required

2.2 Fuel Required

The combustion techniques proposed for this facility are based on "Fuel Conditioning." "Fuel Conditioning" is defined as drying with stack gases, removal of rock and other non-combustible and air classification.

With this quality of fuel available from "Fuel Conditioning," it is possible to take advantage of proven "state of the art" combustion equipment.

A portion (coarse material @ approximately 28 percent H_2O) will be burned, using an air spreader stoker, on grates. The balance will be burned in a true suspension burner where the combustion takes place in the radiant section of the steam generator.

The following tabulation shows the fuel sources and quantities consumed (based on 340 operating days per year) -

Base Case (3 MW production)-

	Tons/Yr B.D. Basis	#/Hr B.D. Basis	As Burned % H_2O Wet Basis	#/Hr Wet Basis
Flodin Shavings	4650	1140	8.4	1244
Flodin Sawdust	4650	1140	8.0	1234
Flodin Hogged Fuel (Fines)	6032	1478	8.0	1606
Flodin Hogged Fuel (Coarse)	12064	2957	28.0	4106
WI Shavings	4133	873	8.0	948

Alternate Case (5 MW production)-

	Tons/Yr B.D. Basis	#/Hr B.D. Basis	As Burned % H_2O Wet Basis	#/Hr Wet Basis
Flodin Shavings	5731	1405	8.4	1534
Flodin Sawdust	5800	1422	8.0	1540
Flodin Hogges Fuel (fines)	7324	1795	8.0	1951
Flodin Hogged Fuel (coarse)	14649	3590	18.0	5129
WI Shavings	4567	1119	8.0	1217
Purchased Fuel (fines)	4414	1082	8.0	1176
Purchased Fuel (coarse)	8826	2163	28.0	3004

Note:

1. For the Base Case, no purchased hogged dead Lodgepole pine is included. Only Flodin plus a portion of the WI shavings are required to satisfy fuel requirements. WI is close and a reliable fuel source. If WI is shut down, LP surplus or hogged dead Lodgepole pine is available.

2. For the Alternate Case, Flodin fuel, plus WI shavings are combined with purchased hogged dead Lodgepole pine to make up the fuel requirement. Other surplus fuel from WI, Thompson Falls and LP, Trout Creek were not required, but remain as alternate fuel sources.

3. Excess air for combustion at design conditions is specified at 10 percent pulverized fuel combustion and 30 percent for coarse fuel combustion.

FUEL QUALITY

Flodin species mix for their sawmill is approximately 50 percent Ponderosa, 25 percent Douglas fir and 25 percent Western larch with other species occasionally mixed in.

The Flodin mix is used to calculate the lower heating value of the fuel and pounds of air for combustion per pound of wood burned.

		Lower Heating Value	
Mix	Species	BTU/#	#Air/# Wood
50%	Ponderosa pine	8245	6.37
25%	Douglas fir	8095	6.29
25%	Western larch	8410	6.45
		8250	6.37

Lodgepole pine heating values and combustion air requirements vary considerably. For the purposes of this study, the LHV and air requirements are assumed to be the same as for the Flodin mix.

Ash content of "Conditioned Fuel" should fall between 1.5 and 3.5 percent on a weight basis.

Moisture contents of available fuels are shown in the tables included in this report.

2.3 FUEL HANDLING PROCESS DESCRIPTION

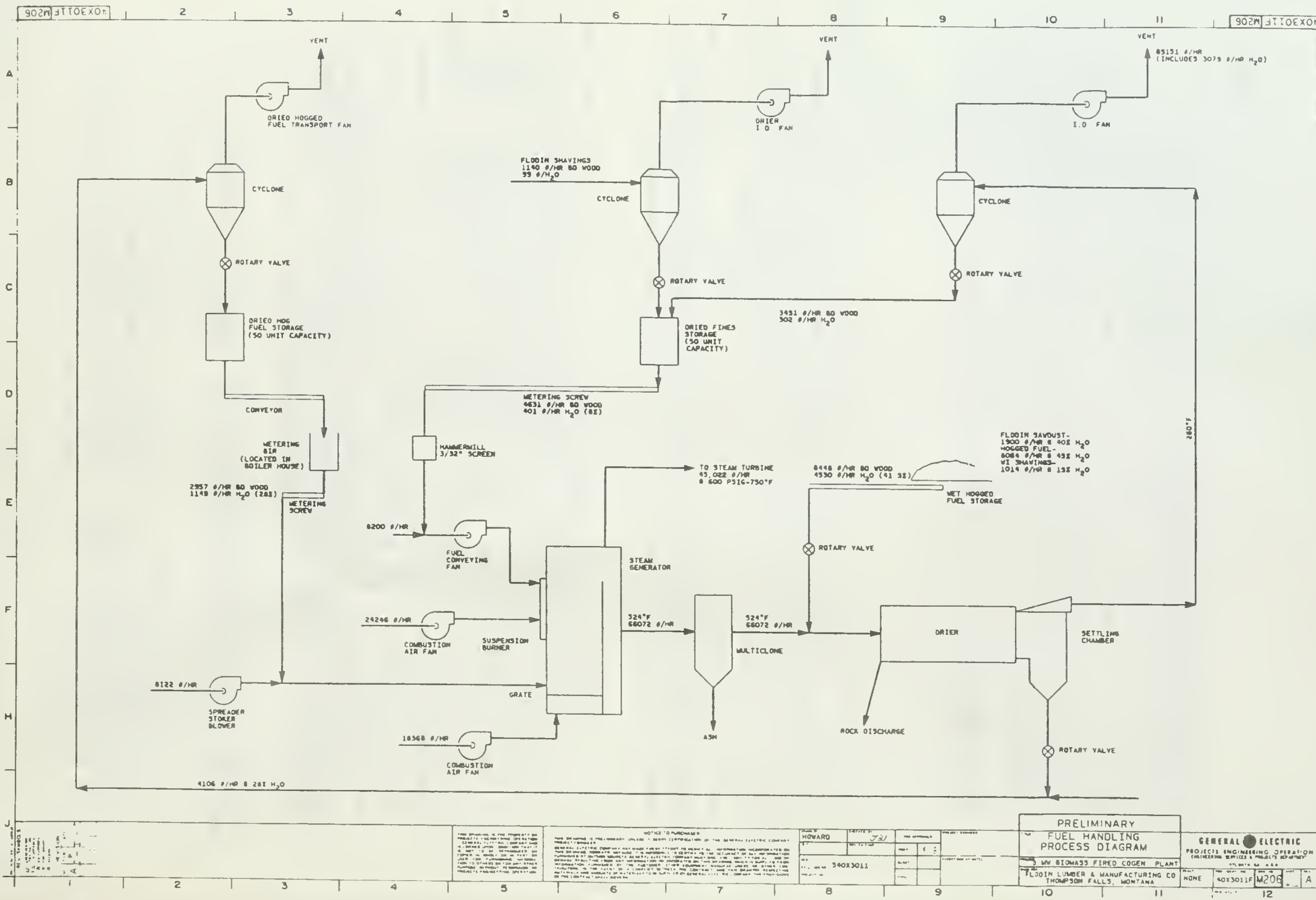
The contract between Montana Department of Natural Resources and Flodin dated 15 January 1983 calls for "Fuel Conditioning" using steam generator stack gases for drying. The heat and material balances calculated for the study were done on the basis of "Fuel Conditioning." The "Fuel Handling Process" diagram shows the heat and material balances calculated on the basis of "Fuel Conditioning."

The central feature of "Fuel Conditioning" is the drying of the fuel. Several different types of driers are commercially available for drying wood particles. For this project, the calculations were made on the basis of using a Thompson single pass rotary drier manufactured by Rader Companies, Inc. of Portland, Oregon. This drier is particularly adapted to fuel drying and has demonstrated successful experience in this field. In addition to drying, "Fuel Conditioning" includes removal of non-combustibles and size separation of the fuel to permit better combustion of the fuel.

A brief description of the proposed facility is as follows: Wet wood fuel is dried using the products of combustion from the steam generator as the heat source for drying. Noncombustibles are removed and the dried wood fuel is separated into two fractions (coarse and light). The coarse fraction is burned on grates in the combustion chamber of a steam generator. The light fraction is further reduced in size and burned in the combustion chamber above the grates using a pulverized fuel suspension burner. This system provides for maximum benefits from dry fuel combustion and eliminates the necessity for fossil fuel. The quantity of steam generated is determined by the actual plant and turbine generator requirement.

For the Base 3 MW Case, the following fuel supply is available:

1.	Flodin shavings	1239 lbs/hr (8% moisture)
2.	Flodin sawdust	1900 lbs/hr (40% moisture)
3.	Flodin Hogged fuel	8064 lbs/hr (45% moisture)
4.	WI shavings	1014 lbs/hr (13.9% moisture)



VENT
DRIED HOGGED FUEL TRANSPORT FAN
CYCLONE
ROTARY VALVE
DRIED HOG FUEL STORAGE (50 UNIT CAPACITY)
CONVEYOR
METERING BIN (LOCATED IN BOILER HOUSE)
2957 #/HR BD WOOD
1149 #/HR H2O (28%)
METERING SCREW
8122 #/HR
SPREADER STOKER BLOWER
VENT
DRIER I D FAN
FLODIN SHAVINGS
1140 #/HR BD WOOD
59 #/H2O
CYCLONE
ROTARY VALVE
DRIED FINES STORAGE (50 UNIT CAPACITY)
METERING SCREW
4631 #/HR BD WOOD
401 #/HR H2O (8%)
HAMMERMILL 3/32" SCREEN
8200 #/HR
FUEL CONVEYING FAN
24246 #/HR
COMBUSTION AIR FAN
SUSPENSION BURNER
GRATE
18368 #/HR
COMBUSTION AIR FAN
STEAM GENERATOR
TO STEAM TURBINE
45,022 #/HR
@ 600 PSIG-750°F
524°F
66072 #/HR
MULTICLONE
ASH
524°F
66072 #/HR
VENT
I.D FAN
85151 #/HR
(INCLUDES 3079 #/HR H2O)
CYCLONE
ROTARY VALVE
3451 #/HR BD WOOD
302 #/HR H2O
FLODIN SAWDUST-
1900 #/HR @ 40% H2O
HOGGED FUEL-
8084 #/HR @ 49% H2O
WI SHAVINGS-
1014 #/HR @ 15% H2O
8448 #/HR BD WOOD
4530 #/HR H2O (41.5%)
WET HOGGED FUEL STORAGE
ROTARY VALVE
DRIER
ROCK DISCHARGE
SETTLING CHAMBER
ROTARY VALVE
280°F
4106 #/HR @ 28% H2O
HOWARD
540X3011
PRELIMINARY
FUEL HANDLING
PROCESS DIAGRAM
5 MW BIOMASS FIRED COGEN PLANT
FLODIN LUMBER & MANUFACTURING CO
THOMPSON FALLS, MONTANA
GENERAL ELECTRIC
PROJECTS ENGINEERING OPERATION
NONE
40X3011F
M206
A
40X3011F M206

Using the above fuel supply, the following flow scheme was laid out:

The three wet wood streams are combined in the Hog Fuel Storage area and metered onto a conveyor which transfers the wet fuel to the inlet end of the Thompson drier. Hot stack gases from the steam generator are combined with the wet fuel at this point.

The Thompson drier incorporates a rock separator which automatically removes rock and other heavy non-combustibles. This separation is accomplished through mechanical means. The Thompson drier incorporates a system of internal baffles to retain the fuel to be dried in the drier until the fuel reaches the desired moisture content. At the outlet of the drier is an air classifier type Settling Chamber which segregates the coarse fraction from the lighter fraction using the air classification principle. Coarse material does not dry as fast or as efficiently as smaller or thinner particles. The coarse material dries to a moisture content range of 25 to 35 percent. The light fraction dries to a moisture content in the range of 6 to 12 percent.

The relative quantity of the light fraction vs. the coarse fraction is largely dependent on the physical shape of the incoming fuel. There is a limited control possible at the Settling Chamber to either increase or decrease the quantity of coarse material. However, small increases or decreases in the percent of fuel going to the coarse fraction does not greatly change the burning characteristics of the fuel.

The coarse fraction from the air classifier is transferred pneumatically through a cyclone and an air lock into the Dried Hog Fuel Storage bin. The Dried Hog Fuel Storage bin may be replaced by a flat Dried Hog Fuel Storage area. The coarse fraction is then conveyed, on demand, to a Metering Bin located in the boiler house. The coarse fraction is burned at the bottom of the combustion chamber (on grates) of the steam generator using an air spreader stoker as the feeding mechanism. This system involves spreading the fuel over iron or ceramic grates. The coarse hog fuel is used as the base load heat input.

The Light fraction from the Settling Chamber is pneumatically conveyed to the Dried Fines Storage Bin through a cyclone and an air lock. The light fraction from the drier is combined in the Dried Fines Storage bin with the dry Flodin shavings.

The Flodin shavings are dry enough for dry fines firing and therefore are not dried in the drier but are transported directly to the Dried Fines Storage bin.

From the Dried Fines Storage bin the light fraction is conveyed, on demand, to a Metering Bin. The light fraction is metered from the Metering Bin through a Hammermill into an air stream that blows the pulverized material through a pulverized fuel suspension burner into the combustion chamber of the steam generator. The pulverized fuel is burned in suspension in the radiant section of the steam generator. Additional combustion air is conveyed through the normal passages of the Dual Air Zone Pulverized Fuel Suspension Burner. The suspension burner used for this study is manufactured by the Coen Company of Burlingame, California.

The drier has several basic control parameters. One is the quantity and size of the coarse fraction that is separated from the light fraction. A second control is the quantity of flue gases passed through the drier. A third and important control is the control that can be gained through the use of an economizer on the boiler feed water pumped to the steam generator. Using a bypass arrangement on the economizer, the flue gases may exit the steam generator at a higher or lower temperature.

The steam generator specified for the Base Case is designed to produce approximately 45,000 lbs/hr of steam at <u>600 psig and 750°</u> F. Throttle steam flow to the steam turbine generator is approximately 38,220 lb/hr with the remaining steam produced by the boiler serving the deaerator and dry kilns.

The stack or flue gases exit the steam generator at approximately 500° F. Since combustion program provides for complete combustion of the fuel, only ash in the form of bottom ash or fly ash remains as a pollutant produced in the steam generator. A high efficiency multiple-cyclone separator is used to remove the fly ash particulate that escape with the is steam generator flue gases. The remaining heavier bottom ash removed from the grates and from the chamber under the grates.

The system described above provides for better and more rapid control of steam generation, less pollution and lower operating cost than a normally fired wet hog fuel boiler. In the design, proposed herein, an air preheater, which would normally be installed on a wet hog fuel fired boiler, is not included. Instead, an economizer, which doesn't have the maintenance problems associated with air preheater, is provided for preheating the boiler feed water and as the control element in the operation of the drier.

In the proposed combustion system, higher flame temperatures are achieved with the combination suspension and grate burning because the drier fuel burns with less excess air and because less heat is lost in the evaporation of the moisture in high moisture content fuels. The suspension burning gives a precise and rapid control of heat input. The combustion is complete, minimizing air pollution problems. The higher flame temperatures and smaller particle size in suspension burning aids combustion. The steam generator itself is less costly and more efficient because of the higher rate of radiation heat transfer. The steam generator will require less maintenance because of lower air velocities in the convection chamber and because no air preheater is required. The ID Fan for the steam generator is smaller and consumes less power.

This system permits the inclusion of a precise burner control and consequently, precise steam production. The pulverized fuel burned has combustion control characteristics similar to a conventional gas or oil burner. Gas or oil burning capability can be included at a minimum cost to provide for steam production when the wood fuel supply might be curtailed.

The 5 MW cogeneration plant will be identical in the "Proposed Flow Scheme." But, the heat and material balance will be increased to satisfy the higher steam demand. The following fuel sources and quantities are used in the design of the 5 MW facility:

1.	Flodin shavings	1527 lbs/hr (8% moisture)
2.	Flodin sawdust	2370 lbs/hr (40% moisture)
3.	Flodin hogged fuel	9971 lbs/hr (45% moisture)
4.	WI shavings	1316 lbs/hr (13.9% moisture)
5.	Purchased hogged Lodgepole pine	4843 lbs/hr (33% moisture)

For the Alternate Case, the steam generator is designed to produce 70,000 lbs/hr of steam at 600 psig and 750° F. 55,000 lbs/hr of the steam is used in the Steam Turbine Generator Unit. 8,700 lbs/hr of steam are available for dry kilns. 6,400 lbs/hr of steam is included in the overall calculation to represent heat loss, blowdown and a small safety factor.

3.0 PLANT SIZE AND CONFIGURATION

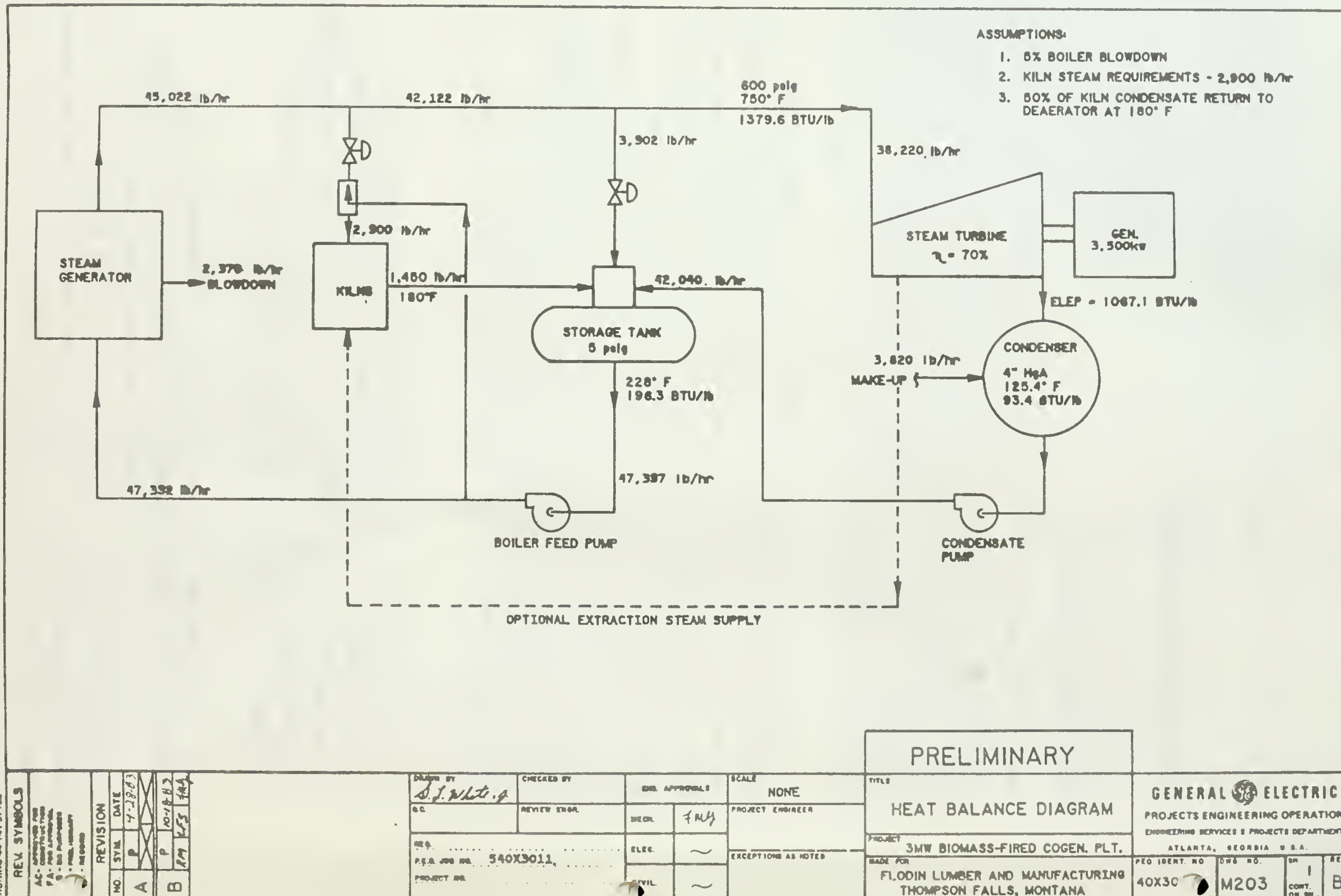
3.1 General Plant Description

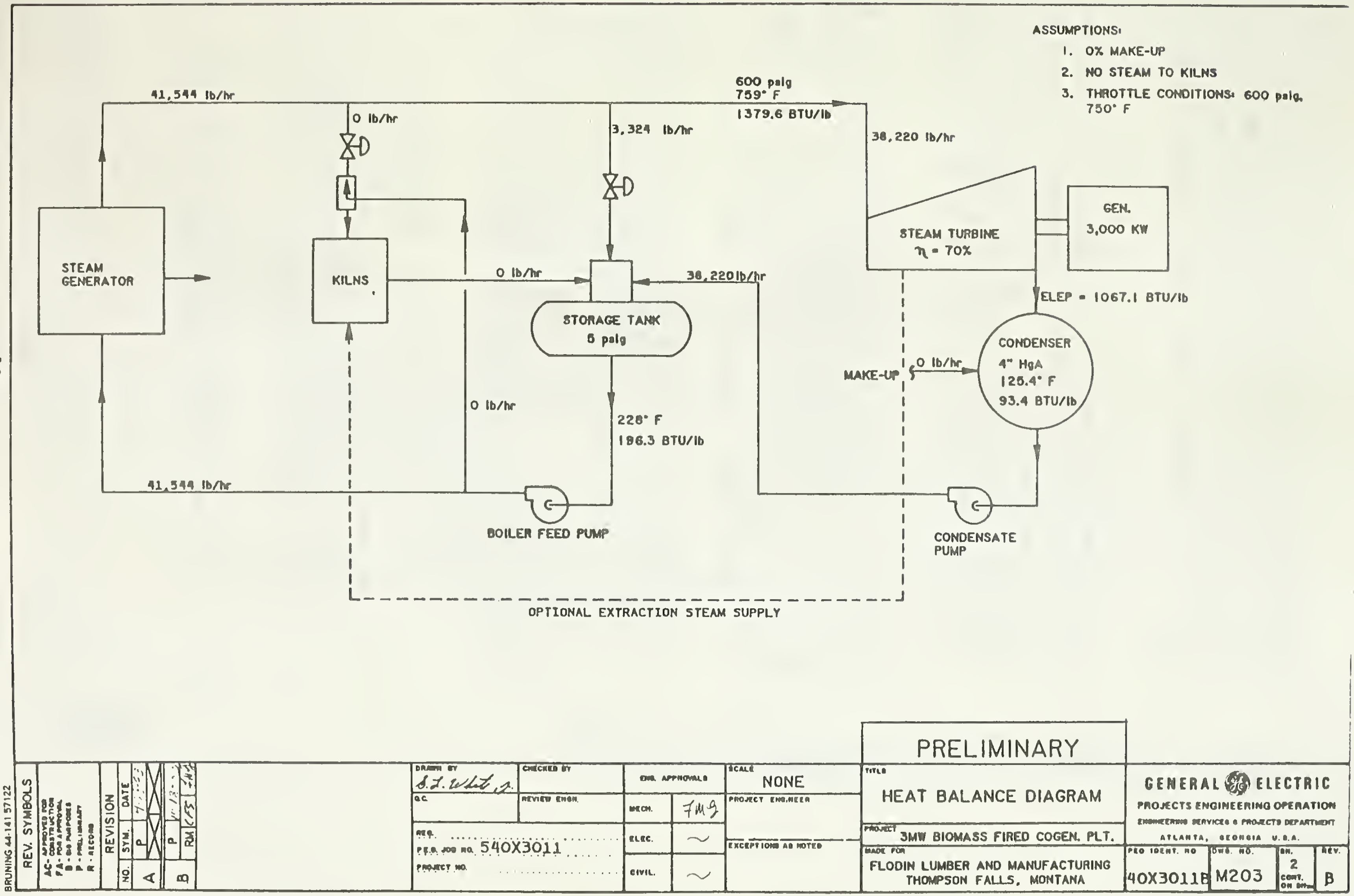
The proposed cogeneration plant consists of a wood fired steam generator coupled with a condensing steam turbine generator. The steam generator, rated to produce 45,000 lb/hr of steam at 600 PSIG and 750°F, supplies high pressure steam to the steam turbine generator, deaerator and wood drying kilns. Drawing No. 40X3011B-M203 depicts the thermal cycle for the generation of steam and power.

The steam turbine converts over 38,220 lb per hour of high pressure steam into 3500 KW of electricity. As there are not any large steam consumers, and due to the low capital cost constraints of this project, the turbine will, in all probability, be a used full condensing type. Although the use of an automatic extraction for the kiln and deaerator steam requirements would result in additional electrical power output, it would limit the used turbine market and add complexity to the operation and maintenance of a machine in this size range. An uncontrolled extraction would be feasible for providing steam to the deaerator, but the fluctuations of the kiln steam would not be suited for that type extraction.

Steam for the wood kilns is extracted from the main header and its pressure reduced to approximately 75 PSIG. A desuperheater designed for the maximum flow rate of 7000 lb per hour reduces the steam temperature to 20°F above saturation, suitable for use in the kiln. The steam flow is regulated in accordance with the requirements of the kiln.

Steam is used in the deaerator to remove any noncondensible gases entrained in the returned condensate. A control valve drops the steam pressure down to 5 PSIG and adjusts the normal flow rate of 3902 lb/hr according to the volume of condensate flowing into the deaerator. This deaerating steam also serves to preheat the condensate preventing thermal shock in the boiler and also improving the efficiency of the thermal cycle.


ASSUMPTIONS:
1. 5% BOILER BLOWDOWN
2. KILN STEAM REQUIREMENTS - 2,900 lb/hr
3. 50% OF KILN CONDENSATE RETURN TO DEAERATOR AT 180° F
STEAM GENERATOR
45,022 lb/hr
2,370 lb/hr BLOWDOWN
42,122 lb/hr
600 psig
750° F
1379.6 BTU/lb
38,220 lb/hr
STEAM TURBINE
η = 70%
GEN. 3,500kw
ELEP = 1067.1 BTU/lb
CONDENSER
4" HgA
125.4° F
93.4 BTU/lb
3,820 lb/hr
MAKE-UP
CONDENSATE PUMP
2,900 lb/hr
KILNS
1,450 lb/hr
180°F
3,902 lb/hr
42,040 lb/hr
STORAGE TANK
5 psig
228° F
196.3 BTU/lb
47,387 lb/hr
BOILER FEED PUMP
47,392 lb/hr
OPTIONAL EXTRACTION STEAM SUPPLY
PRELIMINARY
TITLE HEAT BALANCE DIAGRAM
PROJECT 3MW BIOMASS-FIRED COGEN. PLT.
MADE FOR FLODIN LUMBER AND MANUFACTURING THOMPSON FALLS, MONTANA
GENERAL ELECTRIC
PROJECTS ENGINEERING OPERATION
ENGINEERING SERVICES & PROJECTS DEPARTMENT
ATLANTA, GEORGIA U.S.A.
PEO IDENT. NO 40X30
DWG NO. M203
SH 1
REV. B
SCALE NONE
P.E.O. JOB NO. 540X3011
REVISION
NO. SYM. DATE
A P 4-28-83
B P 10-18-83
REV. SYMBOLS
BRUNING 44-141 57122



ASSUMPTIONS:
1. 0% MAKE-UP
2. NO STEAM TO KILNS
3. THROTTLE CONDITIONS: 600 psig, 750° F
41,544 lb/hr
0 lb/hr
3,324 lb/hr
600 psig
759° F
1379.6 BTU/lb
38,220 lb/hr
STEAM GENERATOR
KILNS
0 lb/hr
STORAGE TANK
5 psig
38,220 lb/hr
STEAM TURBINE
η = 70%
GEN.
3,000 KW
ELEP = 1067.1 BTU/lb
CONDENSER
4" HgA
125.4° F
93.4 BTU/lb
MAKE-UP
0 lb/hr
0 lb/hr
228° F
186.3 BTU/lb
41,544 lb/hr
BOILER FEED PUMP
CONDENSATE PUMP
OPTIONAL EXTRACTION STEAM SUPPLY
PRELIMINARY
REV. SYMBOLS
AC - APPROVED FOR CONSTRUCTION
FA - FOR APPROVAL
B - BID PURPOSES
P - PRELIMINARY
R - RECORD
REVISION
NO.
SYM.
DATE
A
P
B
P
DRAWN BY
CHECKED BY
Q.C.
REVIEW ENGR.
REQ.
P.E.S. JOB NO. 540X3011
PROJECT NO.
ENG. APPROVALS
MECH.
ELEC.
CIVIL.
SCALE
NONE
PROJECT ENGINEER
EXCEPTIONS AS NOTED
TITLE
HEAT BALANCE DIAGRAM
PROJECT
3MW BIOMASS FIRED COGEN. PLT.
MADE FOR
FLODIN LUMBER AND MANUFACTURING
THOMPSON FALLS, MONTANA
GENERAL ELECTRIC
PROJECTS ENGINEERING OPERATION
ENGINEERING SERVICES & PROJECTS DEPARTMENT
ATLANTA, GEORGIA U.S.A.
PEO IDENT. NO
40X3011B
DWG. NO.
M203
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System make-up will be required as steam is lost at the kilns and a certain portion of the condensate is discharged from the boiler steam drum to prevent a buildup of dissolved solids makeup will be pumped into the condenser hotwell from the condensate storage tank.

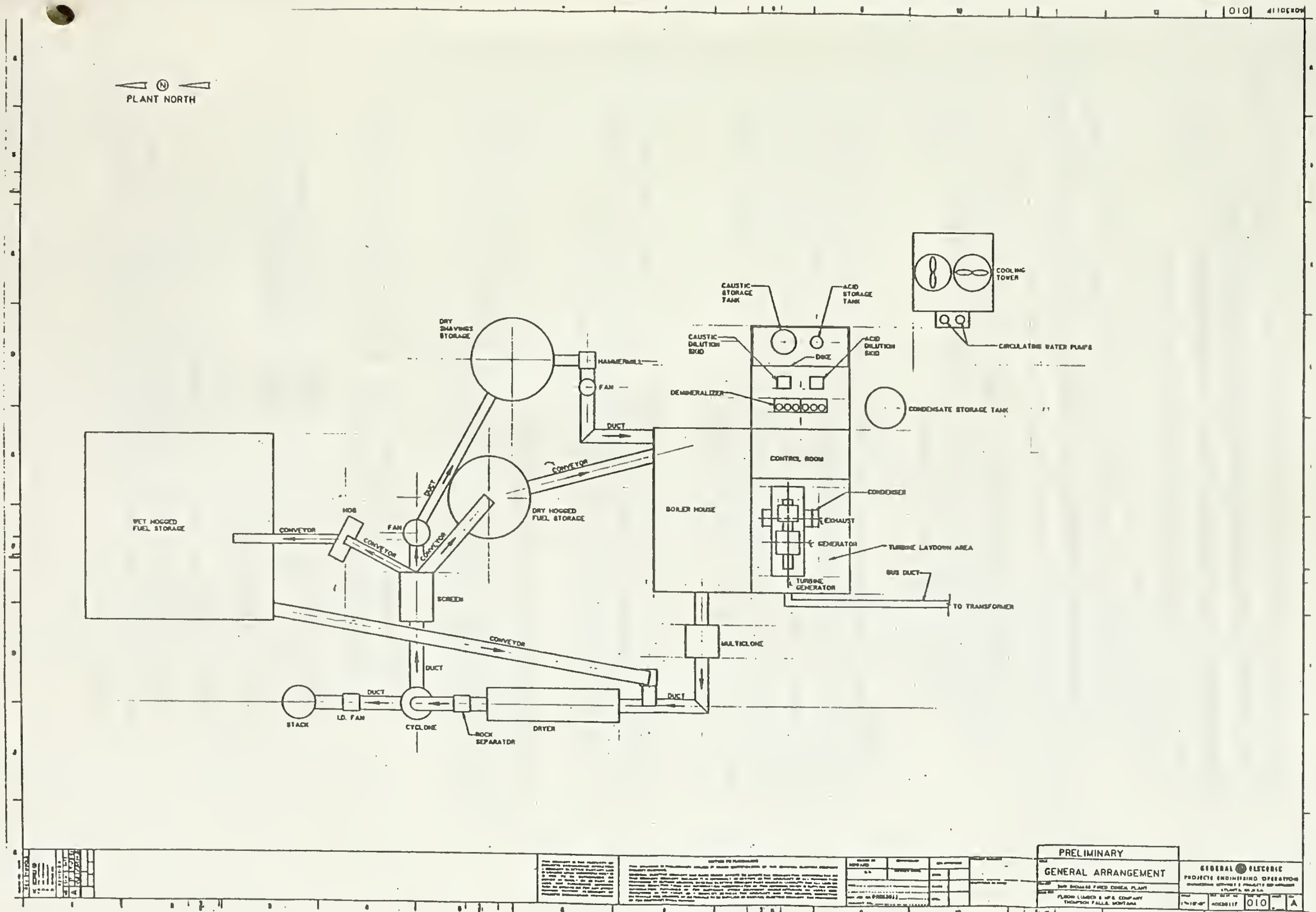
The new cogeneration plant will be located east of and in close proximity of the existing sawmill. The general arrangement of the major equipment comprising the new plant is shown on drawing No. 40X3011-010. The equipment arrangement is a preliminary recommendation and can be easily modified to suit the requirements of the Customer.

The cogeneration facility can be divided into three major systems: fuel handling, steam generation and power generation. The steam generation and power generation systems are described in detail in the following subsections of the report. The description of the fuel handling system is presented in Section 2.0.

The thermal cycle as illustrated in Drawing M-203 with the kiln arranged in parallel with the steam turbine generator does not qualify as a "cogeneration facility" as defined under the Public Utility Regulatory Policies Act (PURPA) of 1978. Instead, the plant is classified as a "small power production facility". The following criteria for a qualifying small power producer as stipulated in the regulations are met:

1. The size of the facility cannot exceed 80 megawatts.
2. The primary energy source of the facility must be biomass waste, renewable resources, geothermal or combination, thereof, which constitutes 75 percent of the total energy input.

In the event a used automatic extraction steam turbine can be



PLANT NORTH
WET HOGGED FUEL STORAGE
CONVEYOR
HOG
DRY SHAVINGS STORAGE
HAMMERMILL
FAN
DUCT
DRY HOGGED FUEL STORAGE
SCREEN
BOILER HOUSE
CONTROL ROOM
CAUSTIC STORAGE TANK
ACID STORAGE TANK
CAUSTIC DILUTION SKID
ACID DILUTION SKID
DIKE
DEMINERALIZER
COOLING TOWER
CIRCULATING WATER PUMPS
CONDENSATE STORAGE TANK
CONDENSER
EXHAUST
GENERATOR
TURBINE LAYDOWN AREA
TURBINE GENERATOR
BUS DUCT
TO TRANSFORMER
MULTICLONE
STACK
I.D. FAN
CYCLONE
ROCK SEPARATOR
DRYER
PRELIMINARY
GENERAL ARRANGEMENT
GENERAL ELECTRIC
PROJECTS ENGINEERING OPERATION
010
A

found, where extraction steam from the turbine is supplied to the kilns as the source of heat, the plant would qualify as a "topping-cycle cogeneration facility under PURPA. The criteria established for this type facility are as follows:

1. The useful thermal energy output of the facility must, during any calender year period, be no less than 5 percent of the total energy output.
2. Since none of the energy input is natural gas or oil, the topping-cycle cogeneration facility will not be subject to any efficiency standard.

In addition, a cogeneration facility or small power production facility must meet the ownership criteria as a qualification requirement. The ownership criteria states that either type "facility may not be owned by a person primarily engaged in the generation or sale of electric power."

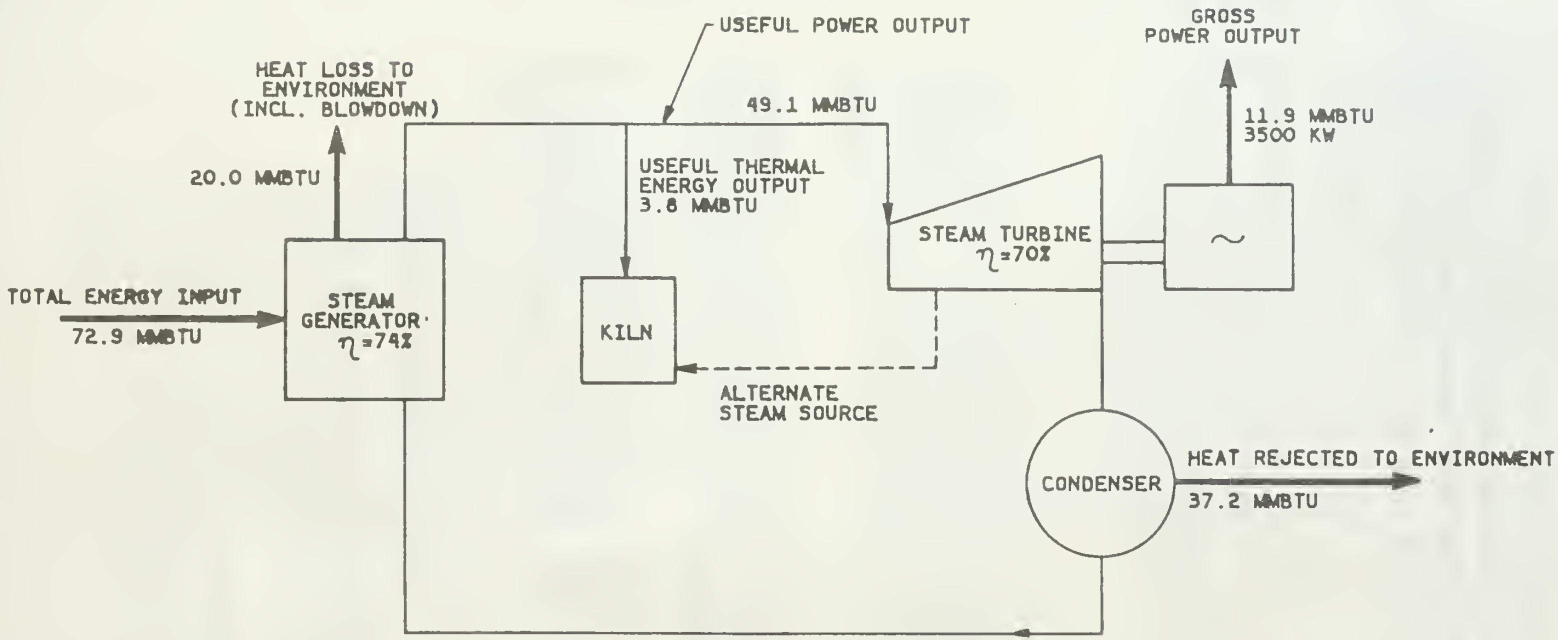
Even though the facility may be either a small power producer or a cogenerator depending on the steam turbine selected, this report will refer to the new facility as a cogeneration plant.

The energy balance for the complete facility is shown on drawing no. 40X3011B-M205. The terminology used in the energy balance is defined in the PURPA regulations as follows:

1. "Total energy input" means the total energy of all forms supplied from external sources;
2. "Total energy output" of a topping-cycle cogeneration facility is the sum of the useful power output and useful thermal energy output;
3. "Useful power output" of a cogeneration facility means the electric or mechanical energy made available for use, exclusive of any such energy used in the power production process.

4. "Useful thermal energy output" of a topping-cycle cogeneration facility means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application.

As previously stated, if extraction steam from the steam turbine is used as the source of heat to the process (i.e. kiln) in lieu of using steam directly from the steam generator, the plant would be classified as a "topping-cycle cogeneration facility.



GROSS PLANT HEAT RATE = 20,840 BTU/KW-HR
GROSS TURBINE HEAT RATE = 14,045 BTU/KW-HR

PRELIMINARY

REV. SYMBOLS	AC - APPROVED FOR CONSTRUCTION; FA - FOR APPROVAL; B - BID PURPOSES; P - PRELIMINARY; R - RECORD
REVISION	NO: A; SYM: P; DATE: 10-18-83
DRAWN BY	R. MARTIN
CHECKED BY	JJ
ENG. APPROVALS	MECH: FMG; ELEC: ~; CIVIL: ~
P&O JOB NO.	540X3011
SCALE	NONE
TITLE	ENERGY BALANCE
PROJECT	3MW BIOMASS-FIRED COGEN. PLANT
MADE FOR	FLOOIN LUMBER AND MANUFACTURING THOMPSON FALLS, MONTANA
	GENERAL ELECTRIC PROJECTS ENGINEERING OPERATION ENGINEERING SERVICES & PROJECTS DEPARTMENT ATLANTA, GEORGIA U.S.A.
PEO IDENT NO	40X301
DWG NO	M205
SH	1
REV	A

3.2 STEAM GENERATION SYSTEM DESCRIPTION

The steam generation facility described herein can be divided into four distinct subsystems: fuel firing, steam generation, combustion air and gas, and ash handling. Descriptions of the equipment and major components of each subsystem are given in Section 3.4.

3.2.1 Fuel Firing System

As discussed in Section 2.0, the fuel firing system for the boiler consists of two fuel flow streams. A dried hog fuel storage bin feeds the coarse fraction of conditioned wood onto the furnace grate via an air spreader stoker. The light fraction of "conditioned" and pulverized fuel wood material is fed through a pulverized fuel suspension burner into the furnace combustion section where the fuel is burned in suspension in the radiant section of the steam generator.

3.2.2 Combustion Air and Gas

Combustion air will be admitted both above and below the boiler grate insuring complete combustion of the fuel. The undergrate air is supplied by the electric motor driven forced draft (FD) fan into the furnace under the water cooled grate. The balance of the combustion air is supplied by the over-fire air (OFA) fan and is admitted through the airswept feeders. This OFA system creates proper furnace turbulence and good combustion to limit environmental problems.

After combustion of the fuel in the furnace, the products of combustion (flue gas) passes through the convection sections of the boiler (i.e. superheater) and out the economizer section. The hot gases are conveyed through ductwork to the multicyclone dustcollector which reduces particulate emissions within acceptable limits.

The flue gas then passes through a wood drier where heat is transferred to dry the incoming wet hogged fuel. Finally, the relatively clean and cool flue gas is discharged by the induced draft fan through the stack and out to atmosphere. Since the furnace is a balance draft type, the induced draft fan essentially pulls or "induces" the flue gas which is discharged by the induced draft fan through the stack and out to atmosphere.

3.2.3 Steam Generation

Hot feedwater from the turbine cycle is initially delivered to the economizer inlet. The economizer, which is a bare tube, counterflow type, adds sensible heat to the feedwater prior to entering the pressure parts of the boiler. The water then enters the boiler natural circulation system. The system comprises a steam drum, water drum, furnace water wall tubes, and front rows of the generating bank. The water is discharged from the steam drum down for recirculation to the steam generating circuits. The water rises through the furnace tubes, absorbing the radient heat from combustion process and is partially boiled. The resultant steam/water mixture is collected in the steam drum where the water and dry steam is separated by the drum internals. The saturated dry steam is subsequently piped to the superheater sections. Radiant and convection heat is transferred from the combustion gas to superheat the steam to the desired temperature of 750° F.

A desuperheating section is utilized for controlling superheater steam outlet temperature within permissible limits.

3.3 POWER GENERATION SYSTEM

The power generation facility is composed of the following mechanical systems described hereafter. The flow diagrams of several of these piping systems are detailed on drawing No. 40X3011-M201 and M202. The equipment and other major components in each system are discussed in Section 3.6.

3.3.1 Main Steam System

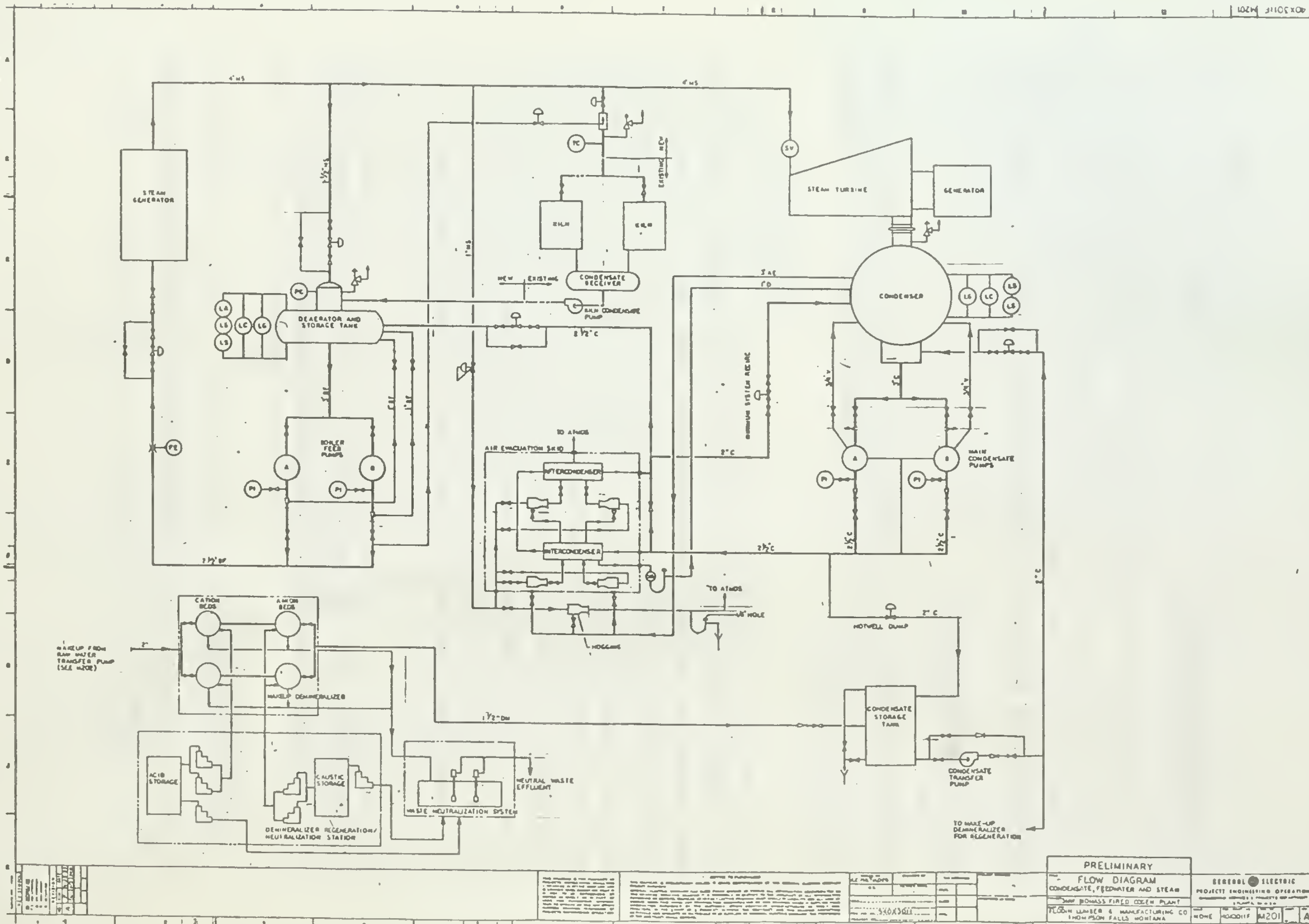
The main steam system is designed to supply medium pressure, superheated steam from the superheater outlet of the steam generator to the stop valve on the steam turbine.

The steam piping is designed for adequate drainage in order to prevent water induction into the turbine during start-up and unit trips. All low point drains are equipped with air operated drain valves. High point vents are located in the main steam piping to vent air during hydrostatic testing. A main throttle-stop valve supplied with the turbine generator for emergency shutoff is located in the main steam piping that leads to the turbine. The stop valve is then connected to the turbine control valves via piping furnished by the turbine manufacturer. The control valve's function is to precisely regulate the speed and load of the turbine by controlling the steam flow into the turbine steam chest.

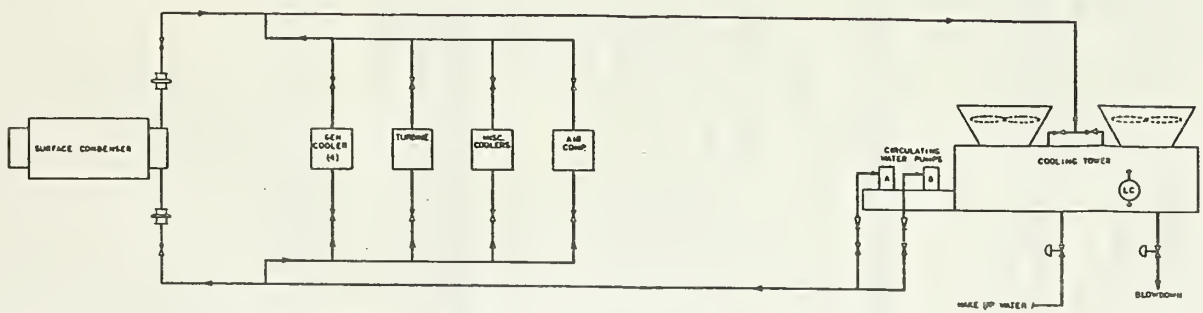
A forged strainer is provided in the throttle-stop valve to prevent foreign objects from entering the turbine. During initial operation, additional fine mesh strainers are added to the permanent strainers.

3.3.2 Condensate System

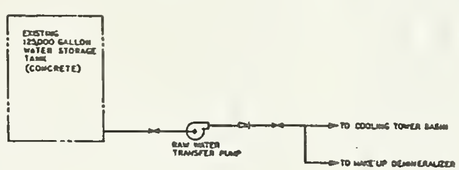
As the steam expands through the steam turbine and flows into the condenser at a backpressure of 4 inches Hga, it produces electricity. After



STEAM GENERATOR
DEAERATOR AND STORAGE TANK
BOILER FEED PUMPS
STEAM TURBINE
GENERATOR
CONDENSER
MAIN CONDENSATE PUMPS
CONDENSATE RECEIVER
NEW
EXISTING
AIR EVACUATION SKID
TO ATMOS
AFTERCONDENSER
INTERCONDENSER
HOGGING
HOTWELL DUMP
CONDENSATE STORAGE TANK
CONDENSATE TRANSFER PUMP
TO MAKE-UP DEMINERALIZER FOR REGENERATION
CATION BEDS
ANION BEDS
MAKEUP DEMINERALIZER
MAKEUP FROM RAW WATER TRANSFER PUMP (SEE M202)
ACID STORAGE
CAUSTIC STORAGE
DEMINERALIZER REGENERATION/ NEUTRALIZATION STATION
WASTE NEUTRALIZATION SYSTEM
NEUTRAL WASTE EFFLUENT
PRELIMINARY
FLOW DIAGRAM
CONDENSATE, FEEDWATER AND STEAM
BIOMASS FIRED COGEN PLANT
THOMPSON FALLS MONTANA
GENERAL ELECTRIC
PROJECTS ENGINEERING OPERATION
NONE
M201
A



COOLING WATER SYSTEM



MAKE UP WATER SYSTEM

PRELIMINARY

FLOW DIAGRAM
MISCELLANEOUS SYSTEMS
3MW BIOMASS FIRED COGEN PLANT
FLODIN LUMBER & MANUFACTURING CO
THOMPSON FALLS, MONTANA

GENERAL ELECTRIC
PROJECTS ENGINEERING OPERATION

NONE | 40X301IF | M202 | A

expansion through the steam turbine, this exhaust steam condenses on the condenser tubes and the resultant condensate is collected in the condenser hotwell. Vertical can type condensate pumps, taking suction from the hotwell, pumps the condensate into the deaerator. Makeup for the condensate storage tank is supplied to the condenser for cycle losses of condensate due to boiler blowdown, leakages, etc.

As the condensate is sprayed into the deaerator, it comes in contact with 5 PSIG steam, which not only heats the fluid, but removes any noncondensible gases which would result in boiler tube pitting and erosion. The deaerated condensate then cascades down into the horizontal storage tank.

3.3.3 Feedwater System

The feedwater system controls and delivers heated feedwater to the economizer inlet of the steam generator under all modes of operation.

Condensate water stored in the deaerator storage tank is pumped by one of the two full capacity boiler feed pumps to the steam generator. The second pump is used as a spare. Each pump is furnished with suction and discharge shutoff valves to permit isolation for a pump that is out of service. Discharge check valves are also provided to protect each pump from reverse flow.

To protect each pump from damage during low load operation, individual automatic minimum recirculation lines are routed from the pumps and discharge back to the deaerator.

Feedwater flow to the generator is regulated by a feedwater control valve by a two-element control system.

Feedwater chemical treatment consists of automatic chemical addition and sampling to protect the boiler and feedwater tubes from corrosion and erosion. The quality of the boiler feedwater passing through the feedwater heater tubes will be limited to:

pH Range	8.8 - 9.2
Solids	1.0 ppm
Oxygen	0.005 cc/1

A solution of hydrazine and ammonium hydroxide is fed into the deaerator outlet piping to remove residual dissolved oxygen from the feedwater and to control feedwater pH.

3.3.4 Condenser Air Evacuation System

The condenser air evacuation system is required to evacuate all noncondensibles and associated water vapor from the condenser to maintain the minimum steam condensing pressure. An adequate amount of water vapor must be vented to insure proper performance of the condenser and to produce reasonable velocities in order to minimize steam side corrosion within the condenser.

Normal air removal or "holding" operation is by means of a twin element, two stage steam jet air ejector equipped with inter and after condenser. A hogging ejector is used to initially pull or "hog" a vacuum in the condenser.

The system and equipment is designed in accordance with the recommendations of the Heat Exchange Institute, "Standards for Steam Surface Condensers."

3.3.5 Circulating Water System

The function of the circulating water system is to provide cooling water to the condenser for removal of the heat rejected from the plant steam cycle.

The system is designed as a closed recirculting pressure system utilizing a cooling tower as a heat sink as opposed to an open system with its objectionable thermal pollution of the river. The cooling water flows throughout the system under a positive head imparted by the circulating water pumps. The water is taken from the cooling tower basin, passes through the condenser, is delivered to the top of the cooling tower, and then it descends by gravity through the tower, dissipating its heat. Makeup water is added to the system to compensate for system water losses due to evaporation, system blowdown and drift.

The cooling tower is a mechanical draft type, consisting of two cells arranged in-line erected on a concrete basin. The tower will be equipped with appropriate freeze protection and reversing fans. A 20°F approach and 25°F range were assumed to minimize the size and cost of the cooling tower and condenser. This design will also allow increased electrical output when the actual wet bulb drops below design as lower cooling water temperatures cause a lower condenser pressure and increased the work done by the steam. The cooling tower basin volume, between the normal and low water levels is designed for five minutes storage at design flow of the circulating water pumps.

The water flows from the divided cooling tower basin through a channel into the screen chamber located in the Circulating Water Pump House. The screen chamber is provided with screen guides for placement of the fixed screens, which are of fine mesh for removing debris which might enter the circulating water pump.

After passing through the screens, the cleaned cooling water enters into the circulating water pump sump.

Two nominal 50 percent capacity vertical circulating water pumps will be installed in the sump located in the Circulating Water Pump House. The pumps are designed to operate in parallel during normal operation, serving the requirements of the condenser cooling water system and closed cooling water system.

The circulating water pump discharge lines which are equipped with a butterfly valve and a rubber expansion joint ties into a common header. The single circulating water line is routed underground to the inlet waterbox of the surface condenser. The circulating water passes through the condenser tubes and is collected in the condenser discharge water boxes. The discharge line from the condenser are connected into a common line which is then routed underground back to the cooling tower.

3.3.6 Boiler Vents and Drains

The boiler vents and drains system is designed to meet the following requirements:

- To discharge saturated water from the boiler by continuous and/or intermittent blowdown, at a flow rate required to maintain an acceptable level of total dissolved solids in the drum.

- To drain the boiler, when necessary.
- To provide for filling and venting the boiler.
- To provide for draining water and venting air and steam from the boiler during startup.

The steam drum will be continuously blown down in order to control boiler water chemistry. The continuous surface blowdown flows from the steam drum through two isolation valves, a manually-operated angle valve and into the blowdown flash tank. The angle valve is provided in order that the blowdown flow rate can be manually regulated.

Upon entering the blowdown tank, a portion of the flow will flash to steam which is vented to atmosphere. The remaining condensate is discharged from the tank through a loop seal, quenched with service water and then emptied into the contaminated waste system.

Miscellaneous vents and drains are provided off the numerous steam and water headers in the boiler. The various boiler drains, where practical, are routed to the boiler blowdown tank.

3.3.7 Turbine Drains System

The turbine drain system serves to provide drainage for the turbine and associated piping. These drains include, but are not necessarily limited to, the following:

- Steam chest drain
- First stage shell drain
- Inner valve steam drain
- High pressure packing leak offs
- Exhaust crossover drain
- Exhaust casing drains

To conserve the usage of demineralized water for makeup, these drains are routed to the condenser to recover the condensate.

3.4 STEAM GENERATOR AND AUXILIARIES EQUIPMENT DESCRIPTIONS

One (1) balanced draft wood fired steam generator will be furnished. The unit will be designed to deliver 45,000 pounds per hour of steam at 600 PSIG and 750°F at the superheater outlet. The steam generator will be supplied with the normal complement of standard accessories together with the additional accessories as described below:

3.4.1 A water-cooled furnace and boiler enclosure of a gas-tight welded wall construction, including but not limited to the following:

1. Furnace welded wall assemblies and headers.
2. Stays, clamps and supports.
3. Drain openings.
4. Acid cleaning connections with blind flanges.
5. Handholes in headers fitted with removable welded handhole caps with machined seats.
6. Access and observation doors.
7. Openings for fuel ports, overfire air ports, soot blower ports and draft sensing ports, etc.
8. Provisions for thermocouples.
9. Provisions for replacement of superheater tubes.

3.4.2 A two drum, bent tube, open pass, balanced draft boiler complete with all the necessary fittings and connections.

3.4.3 A complete superheater from the drum outlet to the non-return valve fitted with all connections and devices required. A desuperheating section shall be furnished, consisting of a spray nozzle (mechanically atomizing type), mixing section with an internal sleeve assembly and complete temperature control system.

3.4.4 An economizer of the bare tube, counterflow type enclosed in a gas-tight steel casing.

3.4.5 A complete fuel firing system will be furnished consisting of the following components:

1. Cast Iron or ceramic grate
2. Air spreader stoker
3. Dual air zone pulverized fuel suspension burner
4. Individual fuel metering bins with metering screws for both coarse fuel and pulverized fuel.
5. Spreader stoker blower
6. Pulverized fuel conveyor fan.

3.4.6 One forced draft fan shall be provided to supply the required combustion air to the boiler. The fan will have a double inlet, double width, backwardly inclined blades with non-overloading characteristics and horizontal shaft complete with the following accessories:

1. Inlet boxes
2. Inlet vanes
3. Inlet silencer
4. Fan bearing assemblies
5. Shift couplings and coupling guards
6. Drive motor with sole plates

The fan drive shall be squirrel cage induction motor, with TEFC enclosure, sleeve bearings, and NEMA Class B or better insulation.

3.4.7 One induced draft fan shall be provided to remove the products of combustion from the boiler. The fan will have a double inlet, double width, radial tip blades with 3/8" full width blade liners and accessories as follows:

1. Inlet boxes
2. Inlet dampers
3. Outlet damper
4. Fan bearing assemblies
5. Shaft couplings
6. Coupling guards
7. Drive motor
8. Motor sole plate

The fan drive shall be squirrel cage induction motor, with TEFC enclosure, sleeve bearings, and NEMA Class B or better insulation.

3.4.8 A mechanical dust collector will be mounted at the outlet of the economizer section to collect dust and flyash in the flue gas leaving the boiler. The collector shall be a high efficiency multicyclone type, complete, including, but not limited to the following components:

1. Casing
2. Hoppers
3. Collecting elements
4. Hopper level sensing
5. Access doors
6. Shop insulation

3.4.9 One steel stack will be provided for discharge of the flue gas to atmosphere. The stack shall be self-supporting and shall include, but not limited to the following items:

1. Stack
2. Base bolting cage
3. Ladder with safety cage
4. Access door
5. Painters trolley
6. Gas duct connections

3.4.10 A complete soot blowing system to serve the steam generating unit shall be included as part of the scope of supply.

3.4.11 All structural steel, insulation and lagging necessary for an outdoor unit.

3.4.12 Access and maintenance platforms and walkways will be furnished as required.

3.4.13 All necessary boiler trim will be supplied including boiler controls.

3.4.14 All ductwork and breeching for the steam generator will be provided.

3.5 Steam Turbine Generator and Auxiliaries Equipment Descriptions

The steam turbine generator will be an indoor condensing unit. The overall plant capital costs were held down by selection of a used turbine generator(see Section 8.1) that is acceptable for the plant steam conditions of 600 PSIG and 750°F at a throttle flow about 38,220 pounds per hour. The unit selected is a General Electric turbine furnished with a 55 PSIG extraction and surface condenser with accessories, and its generator is rated at 3500 KW at 2400 volts, 3 phase, 60 Hz with a 0.80 power factor and is furnished with all accessories. The standard features and accessories provided with the turbine generator are described hereafter.

3.5.1 Control and protective valve systems consisting of the following:

1. Trip throttle valve equipped with hydraulic operator and integral steam strainer:

2. Inlet control valves of a multiple, cam-operated, spring closed, and poppet-type design.

3.5.2 Mechanical Hydraulic Control System

3.5.3 Turbine Control Panel for remote mounting in the Control Room complete with all the standard control features.

3.5.4 Complete lubrication oil system consisting of the following equipment:

1. Main oil reservoir tank of a welded steel construction, furnished with motor driven vapor extractor, oil separator on vapor extraction suction, oil return tray and other standard accessories.

2. Two full capacity shell and tube oil coolers with 5/8 inch OD, 18 BWG. 90-10 Cu-Ni tubes. The coolers are mounted on the tank.

3.5.5 Direct Driven Excitation System will be included.

3.5.6 Switchgear shall also be supplied with the unit.

3.6 BALANCE OF PLANT EQUIPMENT DESCRIPTION

3.6.1 Condenser

A single shell, two pass, divided water box condenser will be provided to condense 40,000 lb/hr of steam flow exhausting from the steam turbine.

The horizontal shop tubed condenser shall be supplied with a deaerating and storage hotwell equipped with a collecting type condensate connection to prevent passage of vapor into the condensate pumps suction in addition to anti-vortexing devices.

The specification for the condenser is as follows:

Quantity	1
Type of condenser	Surface
Back pressure - inches Hga	4
Surface-sq ft	2130
Cooling water required - gpm	2800
Tube velocity - ft/sec	7.0
Cooling water source	Cooling Tower
Cooling water design temp - °F	85
Water box test pressure - PSIG	75
Tubes	3/4" OD, 18 BWG, 15 ft. long (effective)
Tube material	90-10 Cu-Ni 70-30 Cu-Ni*

*For air cooler section

The condenser will also be provided with the following accessories:

a. Hot well gauge glasses
b. Reinforced rubber expansion joint for turbine exhaust
c. Set of special wrenches and tools
d. Air leakage meter
e. All the connections required for heater drains, steam drains, condensate pump recirc, etc.
f. Atmospheric relief valve

3.6.2 Cooling Tower

A two-cell mechanical induced draft cooling shall be field erected and supported upon a reinforced concrete cooling tower basin. The basin shall be sized for adequate cooling water storage. The tower will be constructed of wood or fiberglass and will employ two motor driven fans for air circulation. The cooling tower specifications are tabulated below:

Quantity	1
Type	Mechanical Induced Draft Crossflow
Number of Cells	2
Wet Bulb Design Temperature ° F	65
Approach Temperature, ° F	20
Cooling Tower Range, ° F	25
Cooling Water Flow	3,000 GPM
Fan Horsepower	20 HP Each

3.6.3 Deaerator and Storage Tank

A deaerator and storage tank shall be supplied to obtain an effluent oxygen content of not more than 5 PPB and a CO_2 content of zero. It shall be of the spray tray type vent condenser. The spray system shall be self regulating for varying flow rates. The tray systems shall be designed such that sudden load changes will not disturb the trays. The storage tank (feedwater surge tank) shall be composed of ASTM A-285 Grade C and sized for a seven minute holding time. It shall be provided with a stilling water level baffling arrangement to produce a surface calming effect. The deaerator and storage tank shall be equipped with a relief valve, spring loaded vacuum breaker, gauge glasses, thermometers, vent condenser, impingement baffles, sliding supports and pressure gauges.

Quantity	2
No. of shells	1
Type	Spray Tray
Feedwater entering, lb/hr	41,724 lb/hr
Feedwater leaving	47,392 lb/hr
Recovered condensate	1,450 lb/hr
Feedwater temperature out	228° F
Steam pressure	5 PSIG
Steam flow	3902 lb/hr
Oxygen guarantee	.005 cc/liter
Storage tank capacity	10 minutes
Design pressure	25 PSIG
Design temperature	650° F

3.6.4 Boiler Feed Pumps

Two full capacity boiler feed pumps will take suction from the deaerator and deliver the feedwater to the boiler economizer. An automatically controlled recirculating line will be provided from each boiler feed pump discharge line to the deaerator to meet pump minimum flow requirements.

Quantity	2-100% capacity each
Type	Horizontal centrifugal
Capacity	90 gpm
TDH	1950 ft.
Type fluid	Feedwater
Specific gravity	0.952
Motor HP	75 HP

Materials

Casing	Ductile Iron
Impellers	316 SS
Shaft	SAE 4140
Shaft Sleeves	316 SS
Type Fluid	Feedwater
Specific Gravity	0.952

3.6.5 Circulating Water Pumps

Two half capacity vertical circulating water pumps located in the cooling tower pump sump will be provided to serve the condenser cooling water requirements and the closed cooling water system. The specification for the pumps are as follows:

Quantity	2-50% capacity each
Type	Vertical Centrifugal
Capacity	1500 gpm
TDH	60 ft.
Motor HP	60 HP

Materials

Casing & Casing rings	Cast Iron
Impeller	Bronze
Shaft	Carbon Steel
Shaft Sleeve	Bronze

3.6.6 Condensate Pumps

Two 100% capacity condensate pumps will be provided to pump condensate from the condensate hotwell to the deaerator. The pump is a vertical type with closed or semi-closed type impeller equipped with renewable wear rings. A single condensate pump recirculation will be provided to satisfy pump minimum flow requirements. Each pump will be sized to supply 100 percent of the required condensate flow with all drains discharging to the condenser. The pump will be equipped with a vertical solid shaft drive motor designed for the dead load and thrust of the pump.

Quantity	2-100% capacity each
Type	Vertical Can
Capacity (design)	80 gpm
TDH	165 ft.
NPSH (available)	1 ft.
Motor Horsepower	7 1/2 HP

Materials

Discharge	Steel
Impeller	Bronze
Bowls	Steel or Cast Iron
Shaft and sleeves	11 - 13% Chrome
Suction-can	Steel

3.6.7 Condensate Make-up Pumps

One condensate make-up pump will be provided to supply condensate from the condensate storage tank to the condenser hotwell in the event that the difference in pressure and head between the hotwell and storage tank is insufficient for gravity flow.

Quantity	1 - 100% capacity each
Type	Horizontal Centrifugal
Capacity	15 gpm
TDH	30 ft.
Motor HP	1/3 HP

3.6.8 Steam Jet Air Ejectors

A twin element two-stage steam air ejector will be supplied to evacuate air and noncondensibles from the main condensers. The ejectors will be factory packaged units complete with intercondenser, aftercondenser and all necessary internal piping, fittings, relief valves and isolation valves.

Quantity	2 - 100% capacity each
Type	Condensing Two-Stage Steam Jet
Capacity @ 14.7 psia, 60° F	4 scfm
Dry Air Flow	18 lb/hr
Water Vapor Flow	39.6 lb/hr
Rating Conditions	1" Hga and 71.5° F
Condenser Tube Material	Stainless Steel

3.6.9 Condensate Storage Tank

One 16,000 gallon carbon steel condensate storage tank with plastic liner will be provided to store adequate demineralized water for approximately 12 hours make-up requirements for the turbine cycle. The effluent from the condensate storage tank shall normally flow by pressure differential into the condenser hotwell. One condensate make-up pump will be provided to transfer water when there is not sufficient differential pressure for gravity flow and to supply other demineralized water needs.

3.6.10 Boiler Continuous Blowdown Tank

One ASME code stamped blowdown tank sized to handle continuous boiler blowdown for the boiler will be furnished. Flashed steam will be routed to atmosphere through a swartout head and the drain will be routed to the contaminated waste system.

3.6.11 Demineralizer System

The makeup demineralizer shall be designed to supply the plant with a sufficient quantity and quality of makeup water. The system will consist of two twin bed trains (two cation and two anion exchangers), one month caustic and acid storage tanks, regeneration pumps, and complete control package. Each exchanger vessel will be 30" in diameter with an 84" straight side and will be code stamped for 100 PSIG. Due to the relatively good quality of raw water, the unit will continuously process water for 38 hours before automatically swapping trains. This changeover may be initiated by the operator, timer, flow counter, or effluent conductivity monitor. The regeneration pumps will be the positive displacement diaphragm type and will be provided in sufficient quantity to provide a 100% backup or spare for each train.

The makeup demineralizer will also be supplied with a 4000 gallon neutralization tank. The regeneration backwash will gravity flow into this tank where caustic and/or acid is metered to achieve a neutral waste suitable for disposal or possible plant utilization. The tank will be 9 ft in diameter by 12 ft long and will be supplied with ph monitor, acid and caustic pumps, controls, and an air grid mix system to ensure a homogenous waste.

3.6.12 Instrument Air System Equipment

The instrument air system will consist of one air compressor and one air dryer to meet the instrument air requirements of the entire plant facility. The equipment specifications are as follows:

Air Compressors

Quantity	1
Type	Air cooled, lubricated, rotary screw
Capacity	100 scfm
Discharge Pressure	100 psig
Motor HP	25 HP
Accessories	Controls, aftercooler, air receiver, and starter

Air Dryer

Quantity	1
Type	Heater Dessicant
Inlet Capacity	100 scfm
Outlet DewPoint	-40°F
Accessories	Prefilter and afterfilter

3.6.13 Piping, Valves and Specialties

All piping systems including valves and speciality items will be in accordance with ASME, ASTM, and NFPA codes and will be supplied with suitable materials and be of sufficient size consistent with the fluid flowing through them.

Water Piping

Underground yard piping will be coated and wrapped carbon steel.

Main Steam

Main steam will be delivered from the boiler superheater outlet to the turbine throttle valves through carbon steel pipe A106 Grade B.

Feedwater

Feedwater will be transferred from the boiler feed pump to the economizer inlet through carbon steel pipe (ASTM A106- Grade B).

Condensate

Condensate will be transferred from the condenser hotwell to the boiler feed pump suction through carbon steel pipe (ASTM A106- Grade B).

Miscellaneous System

Piping material suitable for the intended service will be provided for all the auxiliary piping systems.

Valves

The following generic type valves will be specified suitable for the particular application or service: gate, globe, check, ball, butterfly, needle, safety and relief valves, etc. These valves will be furnished in the piping systems as necessary to serve the following functions:

- isolation for inservice maintenance of equipment instruments, and control valves.
- flexibility in system operation
- protection of equipment and systems (such as prevention of reverse flow)

Specialities

Strainers, steam traps, expansion joints, breakdown orifices and other piping specialities will be supplied as required for the piping systems.

3.6.14 Insulation and Lagging

All piping and equipment subject to temperatures above 140°F will be insulated with the proper thickness and type of calcium silicate insulation to minimize heat loses. Where lines subject to temperatures above 140°F do not require insulation to minimize heat losses, such as flowoff lines, insulation will be provided in selected areas for personnel protection only. Metal jackets will be provided over the insulation, except where not practicable to do so.

Prefab jacketing will be used for flanges, fittings and bends for 4 inch nominal pipe size or smaller. For larger fittings, valves, flanges, tanks and heaters, the aluminum jackets with vapor barrier will be field fabricated to follow the contour of the material being insulated.

The insulation and jacketing for access doors, removable panels, manholes, bolted heater head joints, etc., will be done in a manner that will minimize damage to the insulation during access or maintenance periods.

3.6.15 Control Valves

Control valves will be furnished for sytems, subloops and individual services requiring modulating type controls. Control valve design and sizing will be predicated on best engineering practices to prevent flashing and cavitation for high quality, low maintenance components. The control valves shall include but not limited to the following.

1. Condensate makeup control valves
2. Condensate system minimum recirculation control valves
3. Condensate dump valve
4. Deaerator level control valve
5. Boiler feed pump minimum recirculation control valves
6. Feedwater level control valve
7. Cooling tower basin level control valve
8. Deaerator pegging steam pressure reducing valves

3.7 ELECTRICAL SYSTEM AND EQUIPMENT DESCRIPTION

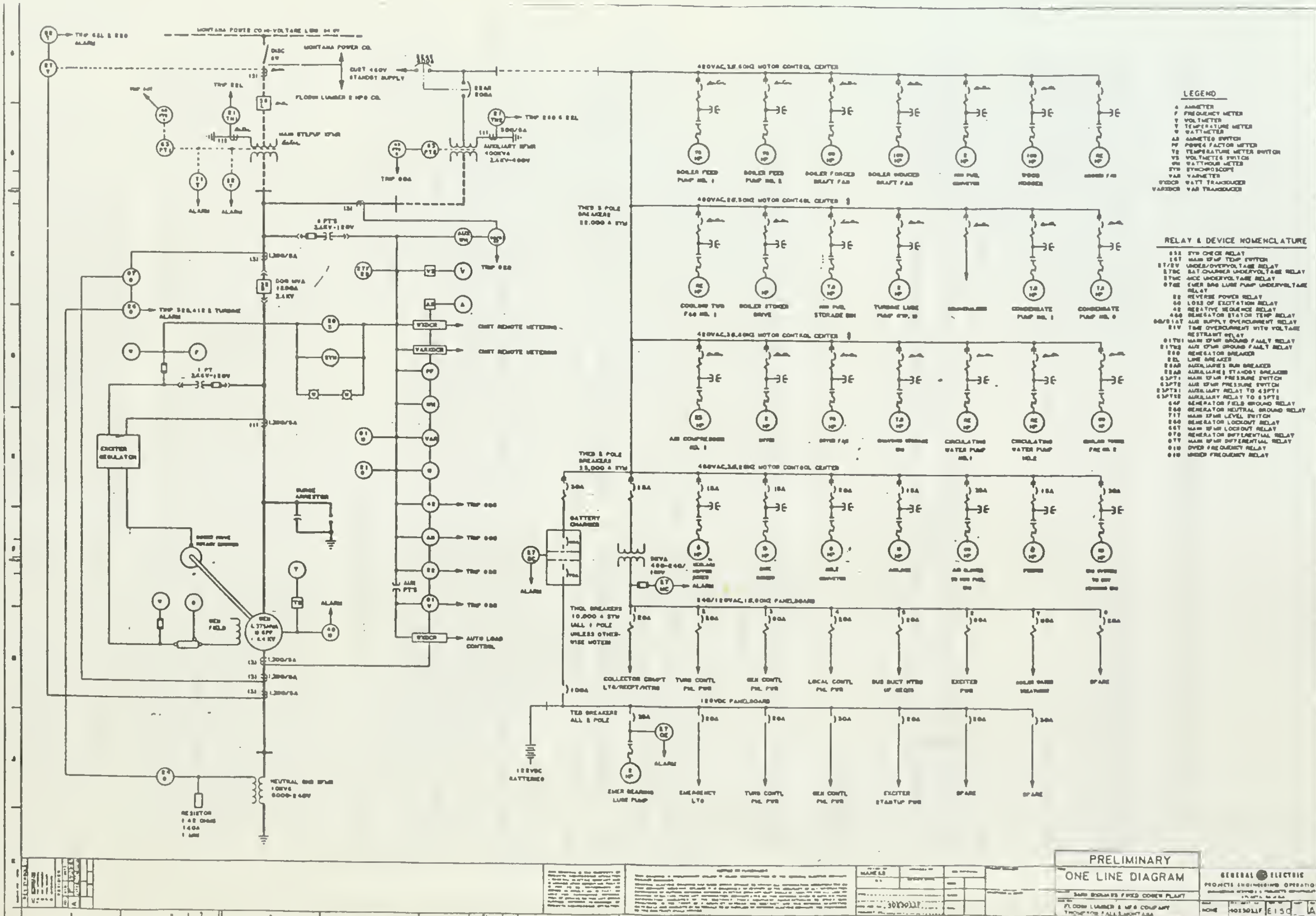
System Interconnection

The proposed electrical systems are shown on the one-line diagram E150.

The system basically consists of (1) steam turbine connected to MPC. The primary point of delivery to MPC will be the 2,400 V side of the utility substation transformer rated at 5 MVA 54/2.4 K.V.

Generation

The electrical system shown on the one-line diagram Drawing No. 40X3011F-E150 is based on a generation capacity of 4375 K.V.A. at 0.8 power factor 3500 kilowatts, 3 phase, 60 cycle. The generator will be a 2-pole machine operating at 3600 R.P.M. and generating 2400 volts. The machine will be directly connected to a condensing turbine. It will be of the rotating field type with a rotary exciter and stationary voltage regulator. Load/speed control will be by governor. The generator will be wye-connected with the neutral grounded through a 2,400 volt to 240 volt distribution type, grounding transformer with a secondary resistance sized to limit the voltage at the generator bus to the minimum valve in the event of an arcing ground fault. The generator main bus will be a cable bus consisting of a number of 5 K.V. cables. The generator protection as shown on one-line diagram consists of:


MONTANA POWER CO. HI-VOLTAGE LINE
MONTANA POWER CO.
CUST 480V STANDBY SUPPLY
FLOOM LUMBER & MFG CO.
MAIN STEPUP XFMR
AUXILIARY XFMR
480VAC,3Ø,60HZ MOTOR CONTROL CENTER
BOILER FEED PUMP NO. 1
BOILER FEED PUMP NO. 2
BOILER FORCED DRAFT FAN
BOILER INDUCED DRAFT FAN
WOOD HOGGER
COOLING TWR FAN NO. 1
BOILER STOKER DRIVE
STORAGE BIN
TURBINE LUBE PUMP
CONDENSATE PUMP NO. 1
CONDENSATE PUMP NO. 2
AIR COMPRESSOR NO. 1
CIRCULATING WATER PUMP NO. 1
CIRCULATING WATER PUMP NO. 2
LEGEND
RELAY & DEVICE NOMENCLATURE
EXCITER REGULATOR
SURGE ARRESTER
BATTERY CHARGER
ALARM
CUST REMOTE METERING
AUTO LOAD CONTROL
NEUTRAL GND XFMR
RESISTOR
120VDC PANELBOARD
120VDC BATTERIES
COLLECTOR COMPT LTG/RECPT/HTRS
TURB CONTL PNL PWR
GEN CONTL PNL PWR
LOCAL CONTL PNL PWR
EXCITER PWR
SPARE
EMER BEARING LUBE PUMP
EMERGENCY LTG
EXCITER STARTUP PWR
PRELIMINARY
ONE LINE DIAGRAM
GENERAL ELECTRIC
PROJECTS ENGINEERING OPERATION
FLOOM LUMBER & MFG COMPANY

25	SYNCHRONIZING OR SYNCHRONISM CHECK
27	UNDERVOLTAGE
32	POWER DIRECTION
40	LOSS OF FIELD DETECTION
46	CURRENT BALANCE
51G	CURRENT BALANCE
51N	VOLTAGE RESTRAINED/CONTROLLED TIME OVERCURRENT
59	OVERVOLTAGE
79	RECLOSING RELAY
81O	OVERFREQUENCY
81U	UNDERFREQUENCY
87	CURRENT DIFFERENTIAL

The following metering is also provided:

° WATTMETER
° WATTHOURMETER
° VARIMETER
° AMMETER
° VOLTMETER
° FREQUENCY METER
° TEMPERATURE METER

Switchyard

This switchyard will be owned and operated by MPC. It will consist of a 2.4 K.V. to 54 K.V. transformer, a 54 K.V. oil circuit breaker and associated 54 and 2.4 K.V. isolating switches. Synchronizing will be done manually through the generator 2.4 K.V. breaker. This transformer will be oil-filled and located in the outdoor switchyard/substation. It will have a rating of approximately 5 MVA. It will be equipped with bushing-type current transformers to provide overcurrent, differential and ground fault protection. The 54 K.V. O.C.B. will be interlocked with the 2.4 K.V. generator circuit breaker. Plant operating power will be supplied by an oil-filled auxiliary transformer rated at 400 KVA and located outdoors. This transformer will transform 2.4 K.V. to the plant utilization voltage of 480 V. This transformer will be Delta connected on the 2.4 K.V. primary side and wye connected on the 480 V secondary side.

In-Plant Systems

Plant equipment and systems will be operated at 480/277 volts and 208/120 volts. Motors 1/2 h.p. through 200 h.p. will operate at 480 volts and will be controlled and protected by the 480 volt motor control centers. The 480/277 volts systems will be supplied by the station auxiliary transformer. This will be throat connected and integrally mounted with the 480 volt switchgear.

A 125 volt D.C. station-service battery system will be utilized to provide switchgear and protective-relaying operating power. In a turbine emergency, it will also provide power for the lube oil pump, turning gear, alarms, and annunciator systems and emergency lighting. The battery will have adequate capacity to bring the turbine-generator to a safe and orderly shutdown in an emergency. An automatic battery charger will be provided with ample capacity to charge the battery system from full discharge within 24 hours while carrying the normal operating load. The plant lighting system will, in general, operate from the 480/277 volt power system. Lighting levels will be in accordance with the Illumination Engineering Society of North American Standards. Emergency lighting will be provided from the station-service battery or individual, self-contained, batterypack type fixtures. The cables carrying 480 volts will be 600 V moisture and heat-resistant cross-linked synthetic polymer insulated cables.

3.8 ELECTRICAL GENERATION

As stated previously, the gross output of the steam turbine generator is 3500 K.W. In order to determine the net export of electricity to the utility, the plant auxiliaries and mechanical/generator losses have to be deducted from the gross output.

The mechanical and generator losses for a turbine generator unit of that size is 100 KW. The plant auxiliaries required for operation of the cogeneration facility are estimted at 400 KW.

Consequently, the net power output of the cogeneration plant is 3000 KW. Based on 8000 hours per year operation, the annual electrical generation will be 24,000,000 KWH.

3.9 EXISTING PLANT ELECTRICAL REQUIREMENTS

The electrical requirements of the existing sawmill facility have been previously served by MPC substation consisting of three 333 KVA transformers. MPC has recently uprated the substation by installing three 833 KVA transformers in place of the smaller units.

The proposed cogeneration plant will not effect the present interconnection between MPC and Flodin's sawmill since the electrical power output will be supplied to MPC transmission grid directly through a step-up transformer.

Even though the cogeneration plant will not directly supply power to the sawmill facility, the monthly mill electrical useage and associated costs from March 1982 to July 1983 are given below for information only:

MONTH	KWH	COST	$/KWH
MARCH, 1982	283200	6226.62	.0219867
APRIL	289600	6229.67	.0215113
MAY	267200	5963.63	.0223190
JUNE	300800	6362.69	.0211526
JULY	233600	5497.04	.0235334
AUGUST	230400	5422.92	.0235370
SEPTEMBER	280000	6079.17	.0217113
OCTOBER	224000	5319.64	.0237484
NOVEMBER	296000	6305.68	.0213030
DECEMBER	292800	7790.24	.0266060
JANUARY, 1983	230400	6882.29	.0298711
FEBRUARY	315200	8256.95	.0261959
MARCH	313600	8051.94	.0256758
APRIL	316800	8144.53	.0257087
MAY	321600	8215.38	.0255453
JUNE	310400	8004.70	.0257883
JULY	302400	7777.77	.0257201

COGENERATION CONSIDERATIONS

The addition of a new biomass (wood) fired boiler and turbine generator is a new venture for many industrials. In determining the feasibility of such a venture, a number of key elements should be addressed.

The following discussion covers several of those elements for detailed consideration: regulatory analysis, tax incentives, utility contract and rate schedules.

4.1 Regulatory Analysis

Federal and state regulatory policies are a heavy influence on the feasibility of cogeneration projects. This Section will address these policies and their effect as positive and negative influences on the total program.

Basically, these regulations were intended to encourage industrial steam and power generation through the use of fuels other than oil or gas. As envisioned, this mission was to be accomplished through smooth progression of laws which sought to provide incentives for energy conservation/independence.

However, the sought after "smooth progression" has proven more cumbersome than originally anticipated by the Department of Energy (DOE), due mainly to regulatory constraints that served as a disincentive to firms interested in cogeneration and small power production. To ease the impact of these constraints, the government, through DOE's Federal Energy Regulatory Administration (ERA), recently promulgated more favorable regulations governing the implementation of the Power Plant and Industrial Fuel Use Act (PIFUA) and the Public Utilities Regulatory Policies Act (PURPA). This then is an identification/analysis of the rules embodying those principles:

The Power Plant and Industrial Fuel Use Act (PIFUA)

Although this law does not exactly provide incentive to pursue alternate fuel use, it does encourage, a lesser dependence on oil and gas. This law, one of five comprised by the National Energy Act of 1978, has undergone continued scrutiny and revision. Among other things the law states:

°An Owner must use alternate fuels (other than gas and oil) for all new boilers with a fuel input of greater than 100 MMBTU's (or for facilities with aggregate input greater then 250 MMBTU's) unless granted an exemption.

°Existing facilities capable of conversion to coal must convert.

°Existing facilities not capable of conversion may have to use a coal-oil mixture.

°Switching from oil to gas is restricted.

°In utility power plants, gas usage can be no larger a proportion of fuel used than it was during the period 1974-1976.

°No Electric Utility use of gas after 1990.

This law as originally drafted proved inflexible, and came under criticism from industry. As a result, DOE moved to simplify and streamline the regulations it set forth on an iterim basis for complying with the coal conversion requirement of PIFUA. Under recent DOE/ERA action the following prevails:

°ERA has issued final regulations covering both new and existing industrial plants that make it considerably simpler for companies to obtain exemptions from the mandate to burn coal.

°ERA has proposed new legislation that would ease the current "cost test" requirement that coal must be proved "substantially more expensive" to use than imported oil before an industrial plant can be excused from burning coal.

These latest developments do not necessarily affect the Flodin Lumber and Manufacturing Company operation, but they do represent what might be perceived as a greater flexibility on the part of DOE in translating the law. Further, and regardless of the administration's latest stance, it should be recalled that although the intent of the law is many-fold, its primary purpose is to conserve natural gas and oil. The law specifies that these "premium" fuels shall be saved for uses for which there are no feasibile alternate fuels or raw material substitutes. The law encourages the greater use of coal/wood and other alternate fuels as a primary energy source in place of gas and oil. Realistically, it remains to be seen what long-term impact the law will really have, although it makes long-range energy planning a critical element in corporate well-being.
The industrial user should certainly plan ahead with a view to adhering to the law.

ERA also has made additional changes in the rules affecting cogenerators. For example:

°On Cogeneration, specifically, DIE's interim-final regulations had required an applicant to show there would be "substantial" oil or gas savings before cogeneration would be considered as an alternative to coalcombustion. The new regulation established regional targets for cogeneration in an effort to promote the use of technology to displace significant portions of oil and gas on a regional, instead of site-specific, basis. DOE's proposed rule would allow up to 1312 MW of new oil-or gas-fired cogeneration in 11 states. In each case, the state governor would have to certify that the cogenerator was eligible to be included under the state limit imposed by DOE, although the state could petition the agency to raise the limit.

°In an alternative proposal, ERA is also considering requiring certification by the state that the cogenerator would be displacing oil and gas, and that it could not use a coal/oil mixture as an alternate. DOE's proposal also significantly changes the method by which cogeneration would be computed, thus freeing more potential cogenerators from the restrictions placed on utilities and allowing additional units to be considered as industrial units.

°DOE's regulations for new units contain far easier reporting requirements than were present in the original issuance of interim-final rules document. The new ruling essentially does away with the fuel decision report that had been criticized as overly burdensome. In place of that report, which required the applicant to survey all possible fuels and alternative generating methods, DOE will now require only that the applicant make a "good faith" effort to find adequate supplies of alternative fuels, and that he supply certain detailed information for the specific exemption that is sought. Under these regulations, all new industrial units must be built to burn a fuel other than oil or natural gas, unless they receive a DOE exemption.

The aforementioned rulings by DOE clearly indicate that the government is moving on several fronts to relax regulatory and economic impediments to cogeneration, and that these moves when aligned with the PURPA incentives, represent significant gains for the cogenerator.

The Public Utility Regulatory Policies Act (PURPA)

Before enactment of PURPA, a cogenerator seeking to establish interconnected operation with a utility faced three major obstacles. First, a utility was not generally required to purchase the output at an appropriate rate. Second, some utilities charged discriminatorily high rates for back-up service to cogenerators. Third, a cogenerator which provided electricity to a utility's grid ran the risk of being considered an electric utility; and thus being subjected to state and federal regulation as an electric utility. Such conditions removed the incentive for on-site power generation at the industrial user level. However, the inception of PURPA in 1978, and the final rule regarding the implementation of Section 210 in February of 1980, has fostered a far different emphasis. The intent is now to encourage cogeneration by reducing regulatory obstacles. Under Section 210 of PURPA, cogeneration facilities that meet certain standards, and are not owned by persons primarily engaged in the generation or sale of electric power can become qualifying facilities, and in so doing become eligible for the rates and exemptions set forth under Section 210 of PURPA.

The following is a series of relevant excerpts from the law as written:

°Each facility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration facilities which obtain qualifying status under Section 201 of PURPA. For such purchases, electric utilities are required to pay rates which are just and reasonable, and do not discriminate against the cogenerator.

°Section 210 also requires electric utilities to provide electric service to qualifying facilities at rates which are just and reasonable, and are nondiscriminatory against cogenerators.

°Such facilities as qualify, are entitled to avail themselves of the rate and exemption provisions under Section 210 of PURPA; also, qualifying cogeneration facilities are eligible for exemption from incremental pricing under Title II of the Natural Gas Policy Act of 1978.*

°Certain interconnection costs may be incurred as a result of sales from a utility to a qualifying facility. FERC prohibits the use of "unreasonable rate structure impediments, such as unreasonable hook-up charges or other discriminatory practices."*

This prohibition is reflected in Section 292.306(a) of these rules, which provides that interconnection costs should be assessed on a nondiscriminatory basis with respect to other customers with similar load characteristics. In addition, state regulatory authorities (such as the Montana Public Service Commission) have the responsibility and authority to ensure that the interconnection requirements are reasonable, and that associated costs are legitimately incurred.

°FERC finds that to require qualifying facilities to go through the complex procedures as set forth in Section 210 of the Federal Power Act to gain interconnection would,in most circumstances, significantly frustrate the achievement of the benefits of the PURPA program, if that Section was the exclusive means of obtaining interconnection. PURPA Section 210 thus provides that an electric utility must make any interconnections necessary to permit purchases from or sales to the qualifying cogeneration facility.

°In the notice of the proposed rulemaking, FERC provided that each utility must offer to operate in parallel with a qualifying cogeneration facility, provided that the qualifying facility complies with standards established by the State Regulatory Authority or non-regulated electric utility with regard to the protection of system reliability pursuant to Section 292.308. By operating in parallel, qualifying facilities are enabled to export automatically any electric energy it does not use.

A critical element of PURPA pertains to "avoided cost." It is this cost which must form the basis for negotiation with the utility. In essence, if, by purchasing electric energy from a qualifying cogeneration facility, a utility can reduce its energy costs (or can avoid purchasing energy from another utility) the rate for a purchase from the cogenerator is to be based on the energy costs the utility can thereby avoid. In a broader sense, "avoided cost" can be defined as the costs to an electric utility of energy or capacity (or both) which, but for the purchase from a qualifying cogenerator, the utility would generate, construct itself, or purchase from another source. This definition is derived from the concept of "the incremental cost to the electric utility of alternative electric energy" set forth in Section 210(d) of PURPA.

Whereas the Montana Public Service Commission can (and does) set forth its assessment of full avoided cost, this number is not without challenge. As an example, MPC currently is seeking reassessment of full avoided cost. MPC maintains that the avoided cost is prohibitively high, and in response has filed a motion for reconsideration. This could result in a reduced assessment.

At the federal level, the U.S. District Court in Washington, D.C. overturned the FERC rules on avoided costs in "American Electric Power versus FERC." In this January 1982 decision, the Court suggested that "the Commision take a harder look at especially the percentage of avoided cost approach" to allow the state commissions to set rates within a certain range (eg 80 to 100 percent of avoided cost). The key point in the Court's decision is that they did <u>not</u> find that full avoided cost was unacceptable.

FERC has since petitioned for a stay of the decision while an appeal is made to the Supreme Court. Since the Supreme Court previously has ruled favorably on the constitutionality of PURPA, it is clear that the avoided cost basis established for utility purchase of cogenerated power will continue regardless of the outcome of the Supreme Court decision.

The motion for reconsideration is not without meaning because it shows that negotiation between the utility and the cogenerator is not inflexible. In effect, an industrial cogenerator can enter with a utility into any contractural agreement that suits his interests or financial requirements, using PURPA as a guideline.

Clearly, cogeneration is "most favored" as a means of obtaining a measure of energy efficiency and independence. PURPA, assures the cogenerator a) he can sell electric energy on a full avoided cost basis, b) receive back-up power and purchase power at nondiscriminatory rates, (c) interconnect on a legitimately incurred costs basis and, d) operate in parallel. The enactment of PURPA is rightly viewed as a major step in that it mandates certain "obligations" by the utility, and in so doing reduces the obstacles attendant to parallel generating operations.

4.2 TAX INCENTIVE

In the Energy Tax Act of 1978, Congress created tax incentives for alternative energy systems. These were expanded and modified in the Crude Oil Windfall Profit Tax Act of 1980. Subsequently, Congress enacted the Economic Recovery Tax Act of 1981 which provides some new incentives for all types of investments.

There are three principal tax incentives which affect cogeneration projects. First, the regular investment tax credit applies to most cogeneration equipment. Second, the energy investment tax credit applies to biomass fired facilities. Third, the Economic Recovery Tax Act allows an accelerated depreciation schedule for rapid capital recovery.

The regular investment tax credit is currently set at ten percent of the cost of a qualified investment. For a cogeneration project, the investment cost for all the components of industrial systems and equipment, excluding buildings, should qualify for the credit.

The Energy Tax Act of 1978 specifically added a provision excluding industrial boilers fueled primarily by oil or natural gas from the regular tax credit.

In addition to the regular investment tax credit, the legislation allows for an additional 10 percent credit for certain classes of energy property, two of which are relevant to cogeneration projects: biomass property and cogeneration equipment. The provision for energy investment credit for cogeneration equipment expired on December 1982. For biomass property, the credit is allowed through 1985.

Biomass property is defined as a boiler or burner that uses some substance other than oil, gas or coal, or products thereof, as more than half its fuel. Equipment for conversion of such a substance into solid synfuel or alcohol also qualifies for the additional tax credit.

The credit for a qualifying boiler normally would extend to the associated fuel handling and pollution control equipment.

The 1981 Economic Recovery Tax Act established a new Accelerated Cost Recovery System (ACRS), whereby qualifying equipment can be written off in five years and most buildings in fifteen years, independent of their physical lives governed under the preexisting IRC Section 167 rules for Asset Depreciation Ranges (ADR).

The biomass property should qualify for the accelerated cost recovery system, and as such, its depreciation schedule for a five-year writeoff is: 15, 22, 21, 21, 21 percent.

4.3 UTILITY RATE SCHEDULES

The Montana Public Service Commission has approved two different tariff schedules which MPC uses for the calculating of payment to qualifying cogeneration (COG) or Small Power Producer (SPP) for the sale of electricity to MPC. The following conditions must be met:

1) Operates a Qualifying COG/SPP facility in accordance with the rules and regulations for COG/SPP Sellers;
2) Has signed the standard contract with the MPC stipulating the terms and conditions of the inter-connection and sale of electricity to MPC;
3) Has agreed in the standard contract to provide electricity to the Montana Power Company either on a short or long term basis.

The two different tariff schedules in effect are for Short Term Power Purchases (STPP) and Long Term Power Purchases (LTPP) which are included herein as Schedule STPP-82-Supplement #1 and Schedule LTPP-82, respectively. For STPP the seller agrees to commit the electrical output of the facility to MPC for a period of at least one year. The seller is paid for the net generation of power (kilowatt hours) exported to MPC's system but is not eligible for compensation for the capacity (kilowatts) of the plant committed to MPC during the contract life. Under the long term power purchase contract agreement, the seller commits the electrical output of the plant for period of at least four years. In addition to the payment for energy, the seller is entitled to payment for the net plant capacity committed to MPC during the contract life.

Under the LTPP contract agreement, the seller commits the electrical output of the plant for at least four years. In addition to the payment for energy, the seller is entitled to payment for the net plant capacity committed to MPC during the contract life.

Both of these payment schedules will be reviewed annually and are subject to revision by MPC with the Public Service Commission's approval whenever there is a change in the avoided costs to the utility for producing or purchasing energy for its customer. Consequently, the rates paid to the cogenerator may go up or down depending on the utility's avoided costs.

MPC will offer a third type of tariff schedule called the Levelized Payment Option in the near future. This option will allow the cogenerator to contract with MPC for a known and fixed levelized rate, which would remain in effect for the life of the contract.

The proposed specifics of the levelized payment option has not been announced, but other utilities have determined the fixed rate by predicting the escalation in the avoided cost over the proposed contract life and to discounting the future rates in order to obtain an "equivalent" annual fixed rate. This would permit the cogenerator to receive a rate higher than avoided costs in the early years of the contract and a lower rate in the latter years, which has the distinct advantage of giving the owner a higher return on investment for the cogeneration plant during the initial years of the contract.

Public Service Commission of Montana

The Montana Power Company
(Name of Company)

Sheet No. STPP-82 Supp. #1
Cancelling Sheet No. STPP-82

Schedule STPP-82 Supp. #1

Short-Term Power Purchase Service

AVAILABILITY: To any Seller who operates facilities for the purpose of generating short-term electric energy in parallel with the Company's system. This schedule is applicable to Cogeneration and Small Power Production (COG/SPP) facilities that are Qualifying Facilities under the Rules of the MPSC.

DEFINITIONS: "Seller," for purposes of this schedule, is any individual, partnership, corporation, association, government agency, political subdivision, municipality, or other entity that:

1. Operates a qualifying COG/SPP facility;
2. Has signed the standard written contract with the Company stipulating the terms and conditions of the interconnection and sale of electricity to the Company;
3. Has agreed in the standard contract to provide electricity to the Company on a short-term basis as defined in the contract.

"Company" means The Montana Power Company.

"MPSC" means The Montana Public Service Commission.

"Contract Year" means twelve months beginning on July 1.

RATE: $0.0234/kWh

SPECIAL TERMS AND CONDITIONS:

1. Change of Rate: This schedule will be reviewed annually for each Contract Year and revised upon MPSC approval.
2. Net Billing Option: If the Seller opts for Short-Term Net Billing in the standard contract and the Seller's consumption kWh exceeds the production kWh, the Seller will be billed for only the consumption kWh in excess of production kWh according to the Company's applicable Retail Sales Rate Schedule. If the Seller's consumption kWh is less than the production kWh, the Seller will receive payment for only the production kWh in excess of consumption kWh according to the energy rate in this schedule. A Seller under this Option will receive no separate payment for capacity, and all metered consumption kW (if applicable) will be billed to

Issued .... (Date) By .... (Signature of Officer of Utility)

Approved .... (Date) Effective .... (Date)

(Space for Stamp or Seal of Commission)

PUBLIC SERVICE COMMISSION OF MONTANA.

.... Secretary.

*Space below these lines for use of Commission only.

Public Service Commission of Montana

The Montana Power Company

(Name of Company)

Sheet No. STPP-82 Supp. #1

Cancelling Sheet No. STPP-82

Schedule STPP-82 Supp. #1

Short-Term Power Purchase Service

the Seller according to the Company's applicable Retail Sales Rate Schedule. If the Seller is demand-metered for consumption, the Seller will be required to install a kW/kWh meter to separately measure production.

3. All service provided by the Company under this and all other schedules is governed by the rules and regulations approved by the MPSC.

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Issued ______ (Date) By ______ (Signature of Officer of Utility)

Approved ______ (Date) Effective ______ (Date)

(Space for Stamp or Seal of Commission)

PUBLIC SERVICE COMMISSION OF MONTANA.

______ Secretary.

*Space below these lines for use of Commission only.

Schedule LTPP-82 Supp. #1

Long-Term Power Purchase Service

AVAILABILITY: To any Seller who operates facilities for the purpose of generating long-term electric energy in parallel with the Company's system. This schedule is applicable to Cogeneration and Small Power Production (COG/SPP) facilities that are Qualifying Facilities under the Rules of the MPSC.

DEFINITIONS: "Seller," for purposes of this schedule, is any individual, partnership, corporation, association, government agency, political subdivision, municipality, or other entity that:

1. Operates a qualifying COG/SPP facility;
2. Has signed the standard written contract with the Company stipulating the terms and conditions of the interconnection and sale of electricity to the Company;
3. Has agreed in the standard contract to provide electricity to the Company on a long-term basis as defined in the contract.

"Company" means The Montana Power Company.

"MPSC" means The Montana Public Service Commission.

"Contract Year" means twelve months beginning on July 1.

RATE: Energy: \$0.0533/kWh

Capacity: The Seller will be compensated monthly for capacity according to the following formula:

$$\$/\text{Annual Contract kW/month} = \frac{\$6.74 \times \text{ACCF}}{.85}$$

where: ACCF = Annual Contract Capacity Factor

Annual Capacity Payment Adjustment: At the end of each Contract Year, a reconciliation of the accumulated monthly capacity payments made to the Seller for the Contract Year and actual capacity value to the Company for the Contract Year will be made utilizing the following formula:

Schedule LTPP-82 Supp. #1

Long-Term Power Purchase Service

$$\$/AAKW = \frac{(80.92 \times ACCF)}{(\quad .85 \quad)} \times \frac{(AACF)}{(ACCF)} \times \frac{(AAKW)}{(ACKW)}$$

Refund to Company = (Dollars Paid to Seller) - ($/AAKW) (AAKW)

Where AAKW = Annual Actual kW (for Contract Year)
ACCF = Annual Contract Capacity Factor
AACF = Annual Actual Capacity Factor (for Contract Year)
ACKW = Annual Contract kW
If AAKW is greater than ACKW then AAKW = ACKW

SPECIAL TERMS AND CONDITIONS:

1. Change of Rate: This schedule will be reviewed annually for each Contract Year and revised upon MPSC approval.

2. Net Billing Option: (A) If the Seller opts for Long-Term Net Billing in the standard contract and the Seller's consumption kWh exceeds the production kWh, the Seller will be billed for only the consumption kWh in excess of production kWh according to the Company's applicable Retail Sales Rate Schedule. If the Seller's consumption kWh is less than the production kWh, the Seller will receive payment for only the production kWh in excess of consumption kWh according to the energy rate in this schedule.

   (B) To meet the conditions of this Option and to receive a separate capacity payment, the Seller's consumption must be measured and billed on a demand basis and a separate kW/kWh meter to measure production is required. Under this Option, the Seller will be billed at the Company's applicable Retail Sales Rate Schedule for only the consumption kW in excess of the production kW. If the Seller's production kW exceeds the consumption kW, the Seller will be compensated for only the production kW in excess of the consumption kW according to the Production Capacity Payment Procedure detailed in this Schedule. The calculation of monthly capacity payments for the expected excess production kW will utilize the expected annual net production capacity factor. The Annual Capacity Payment Adjustment is to be applied to the actual excess production kW for the Contract Year. The procedure will utilize the annual contracted and annual gross production kW and gross capacity factor information for payment reconciliation.

Public Service Commission of Montana

The Montana Power Company

(Name of Company)

Sheet No. LTPP-82 Supp. #1

Cancelling Sheet No. LTPP-82

Schedule LTPP-82 Supp. #1

Long-Term Power Purchase Service

3. All service provided by the Company under this and all other schedules is governed by the rules and regulations approved by the MPSC.

330378

Issued .... (Date) By .... (Signature of Officer of Utility)

Approved .... (Date) Effective .... (Date)

PUBLIC SERVICE COMMISSION OF MONTANA.

(Space for Stamp or Seal of Commission)

*Space below these lines for use of Commission only.

Secretary

UTILITY CONTRACT

A sample contract for power purchase agreement between the Cogenerator or Small Power Producer and the MPC is included in Section C of the "Guidelines for the Interfacing of Cogenerators and Small Power Producers with the Montana Power Company System." The contract as proposed by MPC stresses the protection of the buyer (utility) and to a lesser extent the Seller. The contract in the Appendix of this report should be a good starting point for developing a workable contract agreement between both parties.

5.0 ECONOMIC ANALYSIS

The investment required for a complete power plant facility is a major undertaking for most industrial users. For that reason, it is imperative that the owner have at his disposal a thorough economic analysis of the proposed investment. With that end in mind, this section provides a comprehensive economic analysis for the 3 MW biomass fired cogeneration plant at the Flodin Lumber sawmill.

Estimated power plant costs are examined before the results of the ecomomic analysis are discussed.

5.1 POWER PLANT COSTS

The costs of the biomass fired cogeneration plant can be divided into the following categories:

- Capital Costs
- Fixed Operating Costs
- Variable Operating Costs

5.1.1 Capital Costs

Capital costs of the proposed power plant, as described in Section 3.0, are delineated in Table 5-2. The capital costs include equipment, material, installation, engineering and design, and other costs necessary to furnish a complete operating facility.

TABLE 5 - 1

EQUIPMENT AND MATERIAL

COST SUMMARY *

Item		Cost (1983 Dollars)
Steam Generator		$1,000,000
Turbine Generator (Including refurbishing)		350,000
Fuel Handling System		506,000
Balance of Plant (Mechanical)		
Surface Condenser (Refurbishing Cost Only)	10,000	
Cooling Tower (Including Erection)	60,000	
Demineralizer	104,500	
Deaerator	11,500	
Boiler Feed Pumps	22,300	
Condensate Pumps	12,800	
Circulating Water Pumps	19,700	
Condensate Makeup Pump	1,000	
Condensate Storage Tank	20,000	
Boiler Blowdown Tank	3,000	
Air Compressor & Dryer	7,200	
Ash Handling	50,000	
Piping, Valves, Insulation	100,000	
SUBTOTAL		422,000
Electrical Equipment		
Generator Breaker and Auxiliaries	67,300	
Generator Metering and Relay Panel	70,000	
Step-up Transformer	38,700	
Auxiliary Transformer	9,800	
MCC & Main Breaker	20,000	
High Yard Breaker	43,600	
Installation Materials	60,000	
SUBTOTAL		309,400
TOTAL EQUIPMENT COST		$2,587,400

* Based on current estimates from manufacturers

TABLE 5 - 2

CAPITAL COST SUMMARY

Equipment Costs		
Steam Generator	1,000,000	
Turbine Generator	350,000	
Fuel Handling	506,000	
Balance of Plant (Mechanical)	422,000	
Balance of Plant (Electrical)	309,400	
SUBTOTAL		2,587,400
Installation Costs		
Steam Generator Erection	300,000	
Turbine-Generator Installation	100,000	
Fuel Handling Installation	200,000	
Civil and Structural	371,000	
Mechanical Installation	119,000	
Electrical Installation	40,000	
SUBTOTAL		1,130,000
Engineering and Design		250,000
Contingencies (5%)		198,400
TOTAL		$4,165,800

The equipment costs, summarized in Table 5-1, are based on current estimates from manufacturers. All the equipment prices, except the steam turbine generator and condenser, are based on 1983 dollars for new equipment. The turbine generator and condenser costs include the purchase price of used equipment, removal of equipment from its present sites, transportation and refurbishment.

The itemized list of construction or erection costs are based either on a 1983 composite labor rate of $16.50, or the erection cost as quoted by the equipment manufacturer. The individual installation cost items represent not only the field direct costs, but also the proportional share of field indirect cost, construction management, field adders and profit.

The engineering and design costs are estimated at approximately 6 percent of the total plant cost, or $250,000. This will include complete design services to allow the project to progress from the conceptual phase all the way through final design and construction. A 5 percent contingency fund has been added to the total to account for miscellaneous items not included in this cost breakdown.

The plant would be installed on the site of the existing sawmill, so the cost of land is not included in the capital cost total.

5.1.2 Fixed Operating Cost

The fixed operating costs comprise operating labor, maintenance labor and material, and overhead charges, which are essentially independent of the plant capacity factor.

It is assumed that the personnel now operating the boiler plant would also operate the cogeneration plant. The operating personnel would then consist of one operator per shift and one swing, with no staff required above present levels.

Maintenance labor will be provided by the maintenance personnel already working at the Flodin Lumber Sawmill. Therefore, the cost of maintenance labor for the cogeneration facility is not considered.

The maintenance or replacement material costs associated with the new plant are estimated to be $60,000 per year in 1983 dollars or roughly 1.5 percent of the total capital cost.

Other fixed costs related to ownership of the plant are property taxes and insurance. The annual insurance premium is estimated at approximately $22,000 based on the current rate of $0.53 per $100 insured value that Flodin Lumber is paying for the sawmill. The annual property tax assessed to the cogeneration plant is assumed to be 1 percent of the initial plant cost, or $41,600.

5.1.3 Variable Operating Cost

Variable operating costs depend on or vary with the amount of power produced by the plant. These costs include fuel, water, chemicals, waste disposal, etc.

Water will be supplied from the Clark Fork River, so no cost has been assigned. The pumping costs are included in the inhouse power consumption, which is subtracted from the gross electrical power to yield net salable power.

The cost of chemicals for the demineralizer, boiler chemical injection system and other plant uses is estimated to be $8,500 per year at full load operation in 1983 dollars.

The cost of waste disposal is not considered, because waste is disposed of site.

5.1.4 Fuel Cost

As described in Section 2.0, the fuel for the steam generator is wood shavings, sawdust and hogged fuel. Even though most of the fuel is generated by the sawmill operation, some supplementary wood shavings would be purchased from other sawmill companies. In addition to the cost of purchased fuel, Flodin Lumber has assigned a unit cost to the wood byproducts from the sawmill to properly account for theintrinsic value of the wood shavings and the the cost of processing hogged fuel. The prices assumed for the fuel on a unit basis (i.e. one unit equals 2400 lbs.) are:

Hogged Fuel	-	\$2.50 per unit
Shavings	-	\$5.00 per unit
Sawdust	-	\$2.50 per unit

For the initial year of operation, the total fuel cost for 8000/hr per year operation is tabulated below:

Shavings:	1239 lb/hr x 8000 hr. x \$5.00/2400 lb=	\$20,650
Sawdust:	1900 lb/hr x 8000 hr. x \$2.50/2400 lb=	\$15,833
Hogged Fuel:	8064 lb/hr x 8000 hr. x \$2.50/2400 lb=	\$67,200
Purchased Shavings:	2111 lb/hr x 8000 hr. x \$5.00/2400 lb=	\$35,183
TOTAL FUEL COST		\$138,866

26.3 MMBtus yr

For purposes of this study, the initial fuel cost is rounded up to \$140,000 per year.

5.2 COST ANALYSIS

The economic feasibility of the wood fired cogeneration plant investment is first considered as a "stand alone" project with no credit given for the replacement of the existing antiquated boilers and for the supply of steam to the kilns. The analysis then considers certain credits and adjustments to account for the above factors, thereby arriving at a more realistic comparison of the proposed investment.

Revenues

As discussed in Section 4.3, the sale of electricity to MPC is governed by one of two rate schedules. Schedule LTPP-82 Supp. # 1, which is for long-term power purchase, gives the more favorable terms to Flodin Lumber for electrical sales.

Under this schedule, MPC would pay $0.0533 for each kilowatt hour generated by the qualifying cogeneration facility. Additionally, Flodin Lumber would be compensated for capacity of the facility contracted to MPC under the sell/purchase agreement. The monthly capacity payment is determined from the following formula:

$$\$/\text{Annual Contract KW/Month} = \frac{\$6.74 \times \text{ACCF}}{0.85}$$

Where ACCF = Annual Contract Capacity Factor

Based on an annual generation of 24 million kilowatt hours (see Section 3.8), the first year annual electrical sales for energy is $1,279,200. The annual capacity payment is calculated as follows:

$/Annual Contract KW/Month = $6.74 x 0.908/0.85=$7.20/KW
Monthly Capacity Payment = 3000 x 7.20 = $21,600
Yearly Capacity Payment = 12 x 21,600 = $259,200

The total annual revenues for both energy and capacity payments are $1,538,400. Dividing this annual revenue by the annual generation yields a composite electrical rate (i.e. energy and capacity) of $0.0641/KWH. Assuming annual electrical generation is constant for each year of production, the revenues are escalated at an annual rate of 6 percent.

Operating Expenses

This category covers all the business and plant operating expenses which reduce the tax liability indebted for the gross revenues from the sale of electricity.

In addition to the fixed and variable operating expenses discussed earlier, the interest required to service the debt and the depreciation of the plant equipment are legitimate tax deductions.

For purposes of this study, 100 percent of the plant capital cost is assumed to be financed through a conventional bank loan at 12 percent annual interest rate for a term of 15 years. The annual interest expense declines each year as the loan principal is payed off.

As stated in Section 4.2 Tax Incentives, the proposed facility qualifies for an accelerated depreciation. This depreciation writeoff is 15, 22, 21, 21 and 21 percent of the equipment costs in the first five years. Thereafter, no depreciation for tax purposes is allowed. The analysis considers future inflation, therefore, the fixed and variable operating expenses are assumed to escalate at an annual rate of 6 percent over the 15-year plant life.

Net Income After Taxes

The after tax net income is defined as:

$$\text{After-Tax Income} = (\text{Revenue} - \text{Expenses})\ (1 - \text{Tax Rate})$$

The Federal Tax Rate assigned by the IRS for corporate income is 46 percent.

Debt Service

This category covers the yearly mortgage payment, principal payment and remaining principal balance for the long term financing of the project.

The monthly mortgage payment is calculated by multiplying the amount financed by the Capital Recovery Factor (CRF)

$$\text{Monthly Payment} = \text{Loan Amount} \times \text{CRF}$$

$$\text{Where CRF} = \frac{i\ (1 + i)^n}{(1 + i)^n - 1}$$

For 12 percent APR and 15 years (180 months) financing, CRF = 0.012002

Cash Flow

Annual net cash flow after taxes as used in this analysis is defined as the sum of net income, book depreciation and deferrd taxes (if any). For this report, no distinction is made between book and tax depreciation, so, the depreciation used is the same depreciation listed under operating expenses.

After Tax, Discounted Return on Investment (ROI)

Once the after-tax cash flow is obtained, the economic feasibility of the project can be examined. There are several methods in industry for determining the economic worth of a project: payback, net present worth, equivalent annual worth, and return on investment. This report will look at the after-tax return on investment. The payback method, which has traditionally been used as a benchmark for the economic viability of an investment, does not account for the time value of money, the effect of inflation and escalation in annual fuel, electrical, and labor costs. Return on investment (ROI) more accurately evaluates the impact of rising fuel and electrical costs, labor costs and other costs affected by inflation. The ROI is defined as the annual interest rate which equates the sum of the present value of the net cash flow and the installed equipment cost to zero or, in other words, the interest rate which makes the sum of the present value of the net cash flow equal to the capital investment.

$$0 = -CI + \sum_{j=1}^{n} PWF_j \times AR_j \qquad PWF_j = \frac{1}{(1 + i)^j}$$

Where CI	- Capital Investment (negative cash flow in first year)
PWF_j	- Single payment present work factor which discounts the future net cash flow to its present value.
AR_j	- Net after-tax cash flow
i	- Interest rate on return on investment.

For purposes of this study, the capital investment used in computing the ROI for each alternate is the capital required after deducting the appropriate investment tax credits.

Sensitivity Analysis

From Table 5-3 it can be seen that the cogeneration plant generates an attractive after-tax cost flow throughout the project life. The discounted return on investment for the complete biomass fired cogeneration plant based on this cash flow is 26 percent. Typically, a ROI of 12 to 15 percent is considered as the minimum acceptable rate of return for cogeneration type projects.

Since the return on investment for a particular project is dependent on the capital cost and the revenue generated by the project, a sensitivity analysis has been performed to evaluate the sensitivity of the ROI to changes in the capital cost and sale of electricity.

Figure 5-1 graphically illustrates the impact on the ROI with changes in the composite electrical rate for the sale of electricity to MPC. If MPC is successful in having the Public Service Commission reduce the avoided cost from $0.0641 to $0.04/KWH, the ROI would drop from 26 percent down to 13 percent. Even based on this worst case scenario, the project is still economically feasible.

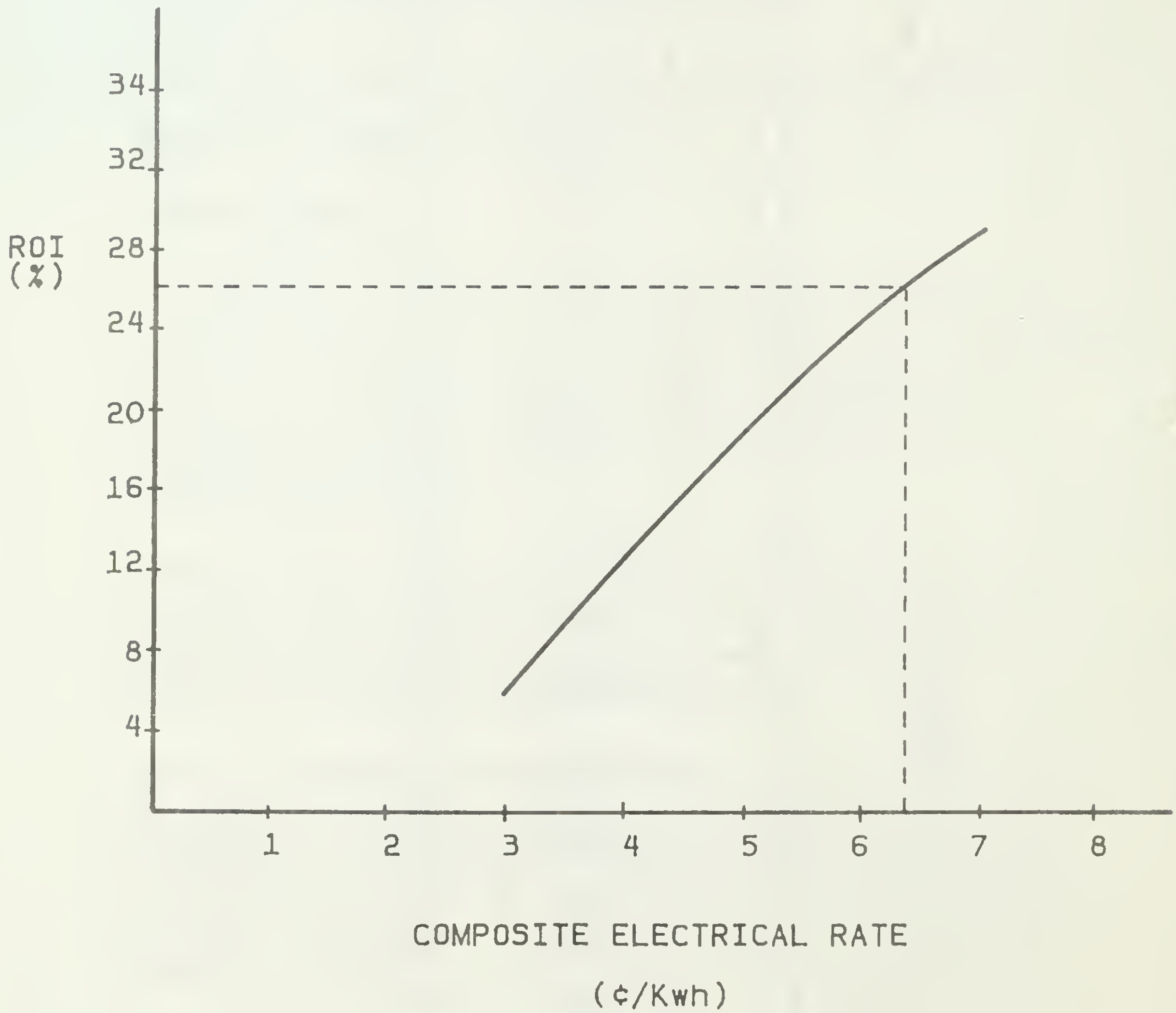
TABLE 5 - 3

CASH FLOW ANALYSIS

YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
CAPITAL INVESTMENT	$4,166,000														
REVENUES															
Sale of Electricity	1,538,400	1,630,704	1,728,550	1,832,260	1,942,190	2,058,730	2,182,250	2,313,180	2,451,980	2,599,090	2,755,040	2,920,340	3,095,560	3,281,300	3,478,170
Credit for Steam Usage															
Subtotal	1,538,400	1,630,704	1,728,550	1,832,260	1,942,190	2,058,730	2,182,250	2,313,180	2,451,980	2,599,090	2,755,040	2,920,340	3,095,560	3,281,300	3,478,170
OPERATING EXPENSES															
Operating Labor, Maintenance, Overhead Charges, Consumables	70,000	74,200	78,652	83,371	88,373	93,676	99,296	105,254	111,569	118,264	125,359	132,881	140,854	149,305	158,263
Fuel	140,000	148,400	157,304	166,742	176,747	187,352	198,593	210,508	223,139	236,527	250,719	265,762	281,708	298,610	316,527
Insurance	22,000	23,320	24,719	26,202	27,775	29,441	31,207	33,080	35,065	37,169	39,399	41,763	44,268	46,924	49,740
Property Taxes	41,600	44,096	46,742	49,546	52,519	55,670	59,010	62,551	66,304	70,282	74,499	78,969	83,707	88,730	94,054
Loan Interest	494,229	480,816	465,706	448,671	429,480	407,855	383,488	356,030	325,090	290,227	250,941	206,673	156,791	100,583	37,245
Depreciation	624,900	916,520	874,860	874,860	874,860	0	0	0		0	0	0		0	0
Subtotal	1,392,730	1,687,350	1,647,980	1,649,390	1,649,750	773,994	771,595	767,424	761,167	752,468	740,917	726,048	707,328	684,152	655,829
NET INCOME AFTER TAXES	78,663	-30,590	43,507	98,748	157,918	693,756	761,754	834,711	913,037	997,178	1,087,630	1,184,920	1,289,650	1,402,460	1,524,070
DEBT SERVICE															
Mortgage Payment	599,988													599,988	599,988
Principal Payment	105,759	119,172	134,286	151,317	170,508	192,133	216,500	243,958	274,898	309,761	349,047	393,315	443,197	499,406	562,743
Principal Balance	4,060,240	3,941,070	3,806,780	3,655,460	3,484,960	3,292,820	3,076,320	2,832,370	2,557,470	2,247,710	1,898,660	1,505,350	1,062,150	562,743	0
NET CASH FLOW	703,563	885,930	918,367	973,608	1,032,780	693,756	761,754	834,711	913,037	997,178	1,087,630	1,184,920	1,289,650	1,402,460	1,524,070
DISCOUNTED ROI	26%														

FIGURE 5-1

SENSITIVITY ANALYSIS
ROI VS. ELECTRICAL RATE



The effect of varying the initial capital investment on the ROI is depicted in Figure 5-2. As can be expected, the ROI increases as the capital cost is decreased. Assuming a band of $\pm$ 25 percent on the capital cost estimate of $4,166,000, the ROI would range from 21 percent to 34 percent.

Generating Costs

The generating costs associated with the generation and sale of electrical power over a 15-year operating period are given in Table 5-4.

FIGURE 5-2

SENSITIVITY ANALYSIS
ROI VS. CAPITAL COST

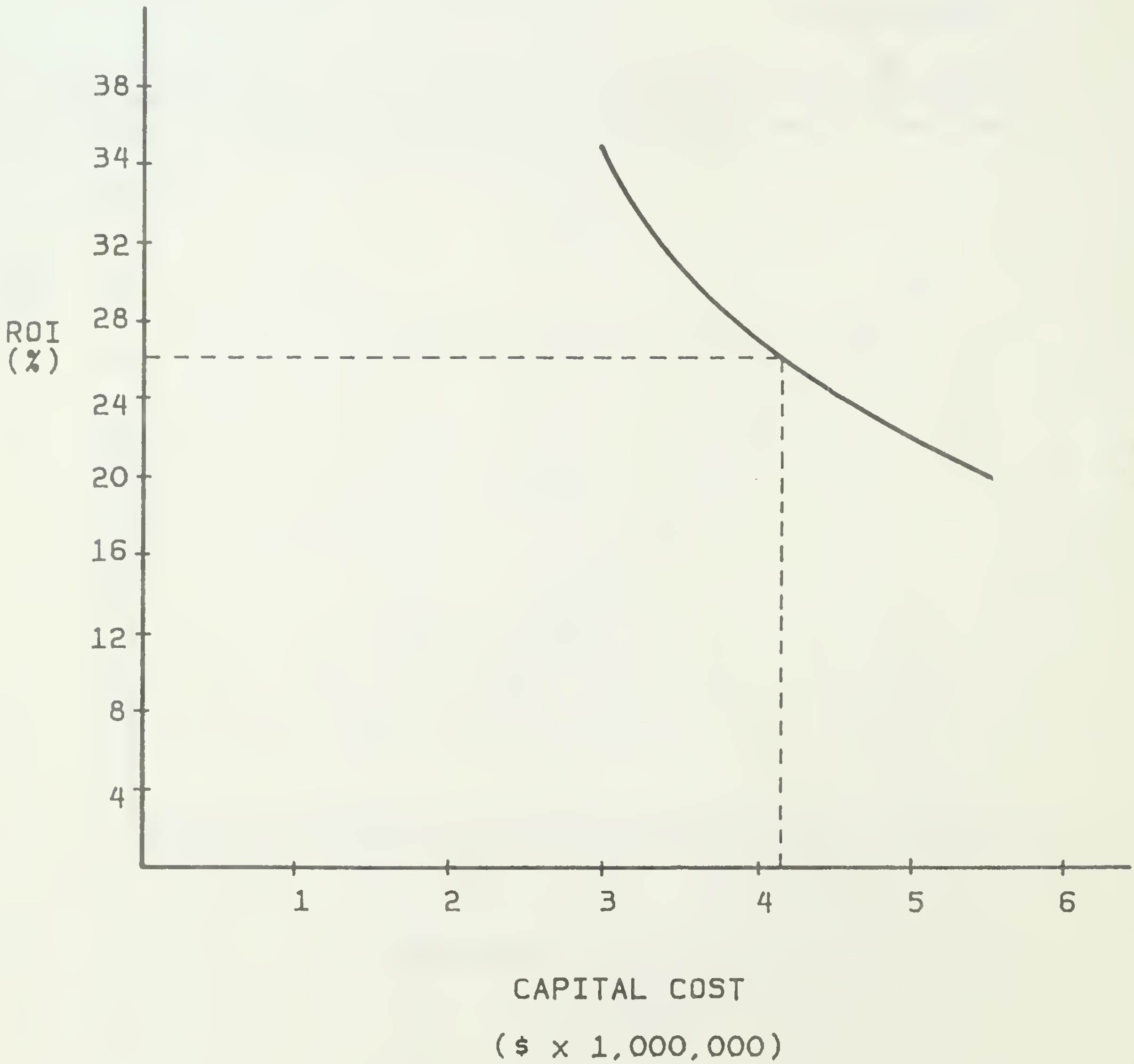


FIGURE 5-4

Generating Costs (mills/Kwh)

Year	O & M	Fuel	Insurance Taxes	Total
1	2.9	5.8	2.7	11.4
2	3.1	6.2	2.8	12.1
3	3.3	6.6	3.0	12.8
4	3.5	6.9	3.2	13.6
5	3.7	7.4	3.3	14.4
6	3.9	7.8	3.5	15.3
7	4.1	8.3	3.8	16.2
8	4.4	8.8	4.0	17.1
9	4.6	9.3	4.2	18.2
10	4.9	9.9	4.5	19.3
11	5.2	10.4	4.7	20.4
12	5.5	11.1	5.0	21.6
13	5.9	11.7	5.3	22.9
14	6.2	12.4	5.7	24.3
15	6.6	13.2	6.0	25.8

5.3 FINANCING

The following financing alternatives have been examined sources of funds for construction of the plant:

1. Economic Development Administration
2. Rural Electrification Administration
3. Department of Natural Resources
4. Conventional Bank Financing
5. Industrial Revenue Bonds

There are other options which can be pursued such as leasing or third party ownership and limited partnerships, but these are beyond the scope of this report.

Economic Development Administration - Grants

According to the chief of the Business Loan Division of the EDA, grants are given only to municipalities and cities whereas grants to private parties, individuals or companies are illegal. Consequently, with private ownership of the cogeneration, Flodin Lumber would not be entitled to receive a grant from the Economic Development Administration.

Rural Electrification Administration - Funding

The Rural Electrification Administration makes loans to utilities in rural areas. In order to obtain a REA guaranteed loan commitment, an electric cooperative would have to have ownership of the power plant.

Department of Natural Resources - Grants and Loans

The Montana Department of Natural Resources and Conservation (DNRC) has established a Renewable Energy Program to reduce the state's reliance on fossil fuels through the increased use of alternate fuels such as biomass. This program funded through Montana's Coal Severance Tax offers grants or loans to encourage the private sector's involvement in renewable energy.

The grant program is restricted to research, development and demonstration projects, whereas the loan program encompasses commercial ventures and projects which have an income generating potential.

For fiscal year 1983, the maximum loan amount available to a single borrower is limited to $202,500 with repayment to be made within 10 years. This program does apply to facilities which sell electricity to the utility grid under the Public Utilities Regulatory Policy Act.

Conventional Bank Loans

The project cost could be financed through a conventional bank loan. Given that the loan would be borrowing against the value of the plant and the credit of the owner, the banking institution would most likely be interested in the following information:

1) Credit history of the borrower
2) A projected income and cash flow statement showing the profits and cash flow produced by project.
3) The power purchase agreement or contract between the cogenerator and the utility.
4) Fuel supply contract (if any).
5) The ability of the project to service the debt in the event of a cutback in the sawmill operation due to a recession or downturn in the lumber industry.

Upon analyzing this data, the bank would assess the credit worthiness of the owner, the economic feasibility of the project and risks associated with the project. As a portion of the bank's business is making loans, a bank probably would be willing to finance the project if it were satisfied with the items. Interest rates for conventional bank loans for industrial projects of this magnitude average about 12 percent.

Industrial Revenue Bonds

Repayment of the bonds would be strictly from the revenues generated by the project. Therefore, the bonds would be secured only by the project revenues and the credit of the owner. The bonds can be issued for periods of up to 30 years, but shorter terms are normally preferred to improve acceptance in the bond market.

At present, tax exempt bonds can be issued at an interest rate of approximately 8.0 percent. Several type of bonds which are issued under the auspices of state and local governments are:

--Pollution control revenue bonds, available to finance the installation of equipment designed to control or abate pollution. There is no ceiling on the amount of bonds that may be issued for this purpose.

--County Government can issue power option bonds to finance construction of electric generating plants. The power must be sold within the county area where it is generated to qualify for financing by this method.

--Solid waste disposal bonds may be issued to finance solid waste disposal facilities. The Federal IRS has said that waste material which has value or will obtain a value is not eligible for tax exemption. The IRS does not consider wood residue a solid waste disposal problem. Thus, this financing option is available only if refuse derived fuel (RDF) is burned in the furnace, and may not be available if the RDF is considered to have a value.

--Economic development revenue bonds are issued for the purpose of expanding the economy through the creation of jobs and increasing the property tax base. The facility must be located in an economically lagging area. Usually, state law prohibits use of revenue bonds for any facility designed primarily for generation, transmission, sale, or distribution of electrical energy. Therefore, financing of the turbine generator by this method would not be permitted.

6.0 IMPLEMENTATION

6.1 Siting

The proposed biomass fired cogeneration facility will be located in Sanders County (Section 18, Township 49W, Range 28u), Montana, approximately 5 miles from Thompson Falls, on property owned by Flodin Lumber and Manufacturing Comapny. The new facility will be situated adjacent to the existing sawmill as shown on the Plot Plan, Drawing No. 40X3011F-001.

The climatic conditions for the site which would be considered in the design of the plant are tabulated below:

Site Elevation above mean sea level	2500 ft.
Maximum ambient air temperature	95°F
Minimum ambient air temperature	-16°F
Design Summer Wet Bulb Temperature	65°F
Relative Humidity Range	40-100%
Annual Rainfall	
Earthquake Zone (UBC)	2
Design Wind Velocity	90 MPH

Access to the site is from State Highway 200 running along the western property line.

Water Source and Requirements

Makeup water for the new facility will be obtained from the existing 110,000 gallon raw water storage tank. The tank receives water pumped from the Clark Fork, which runs along the boundary of the property. The analysis of the river water is given in Table 6-1.

The maximum requirements for makeup water to the plant is approximatley 122 GPM as shown on the Water Balance, Drawing No. 40X3011F-M204. Essentially, makeup is required only for the thermal cycle and cooling water cycle. Makeup to the thermal cycle is required for cycle losses incurred from boiler blowdown and unrecovered condensate from the kilns.

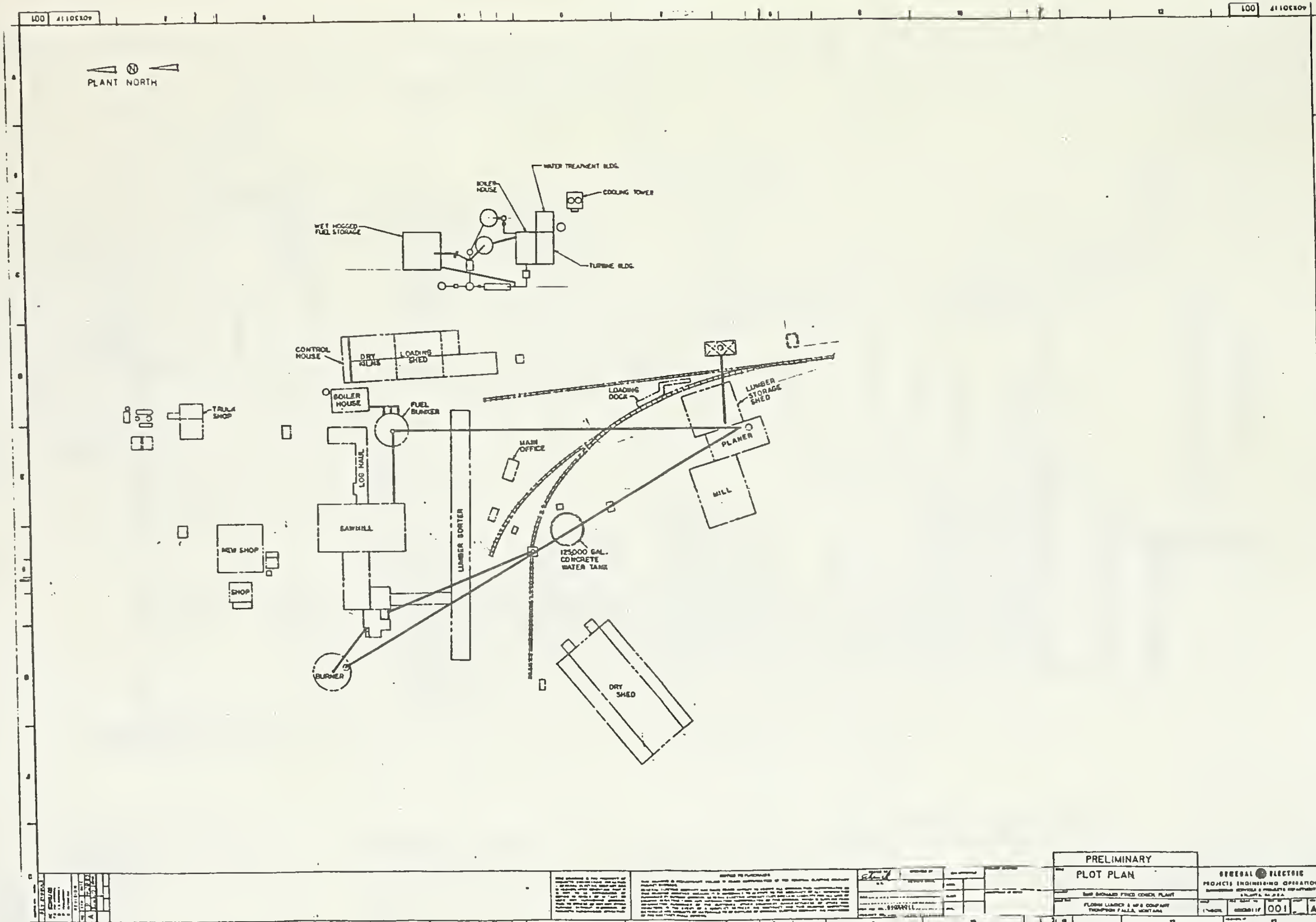
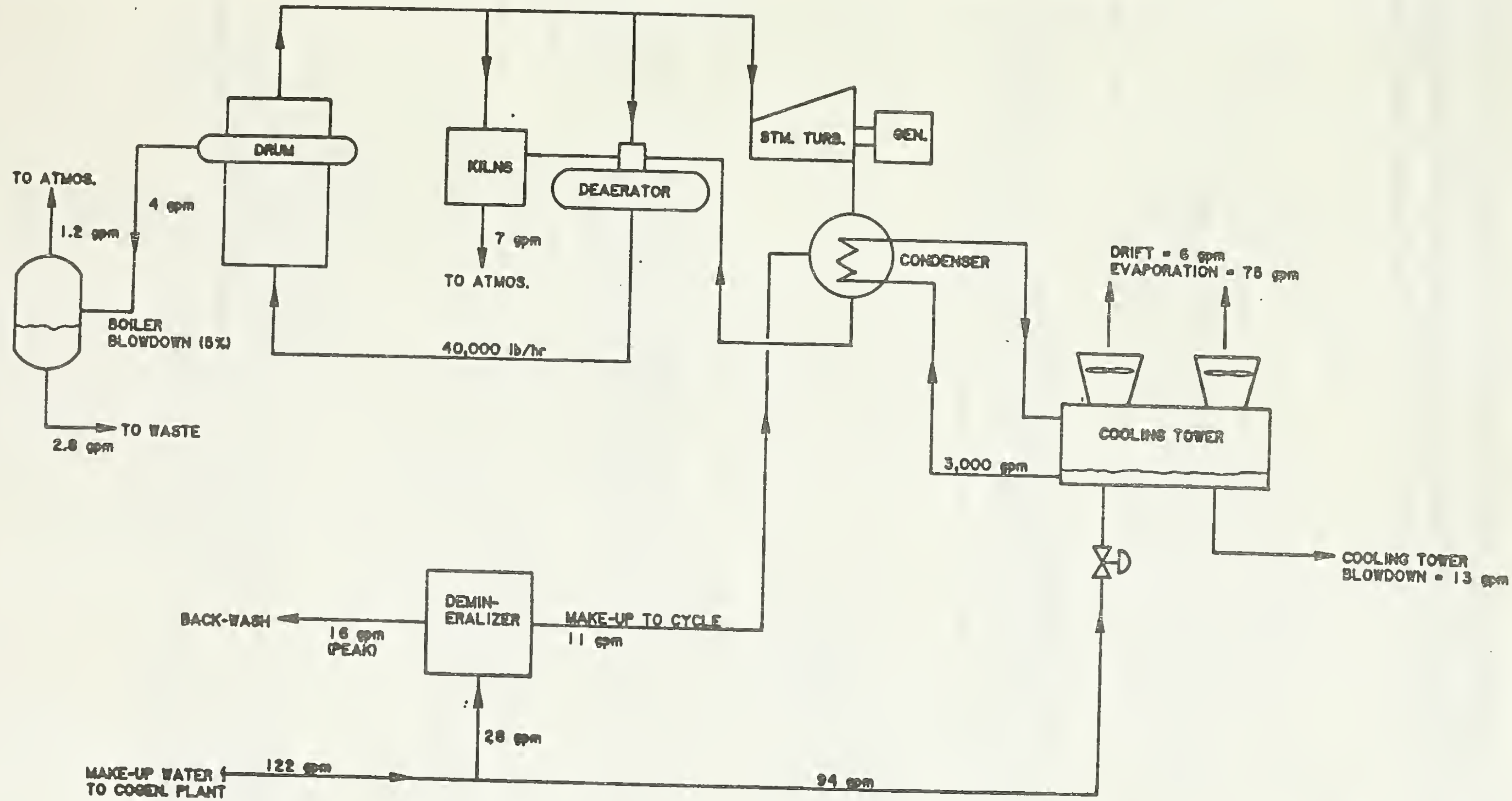

PLANT NORTH
WATER TREATMENT BLDG.
COOLING TOWER
BOILER HOUSE
WET HOGGED FUEL STORAGE
TURBINE BLDG.
CONTROL HOUSE
DRY KILNS
LOADING SHED
BOILER HOUSE
FUEL BUNKER
TRUCK SHOP
LOG HAUL
SAWMILL
NEW SHOP
SHOP
LUMBER SORTER
MAIN OFFICE
LOADING DOCK
LUMBER STORAGE SHED
PLANER
MILL
125,000 GAL. CONCRETE WATER TANK
BURNER
DRY SHED
PRELIMINARY
PLOT PLAN
GENERAL ELECTRIC
001
A

TABLE 6-1

RIVER WATER ANALYSIS

*SAMPLE MARKED	River Water
*ANALYSIS NUMBER	2430-1
pH	7.95
Phenolphthalein Alkalinity as $CaCO_3$, ppm	0
Total Alkalinity as $CaCO_3$, ppm	99.0
Hydrate Alkalinity as $CaCO_3$, ppm	-
Chloride as Cl, ppm	1.0
Sulfate as SO_4, ppm	17.0
Silica as SiO_2, ppm	8.0
Total Hardness as $CaCO_3$, ppm	112.0
Calcium Hardness as $CaCO_3$, ppm	72.0
Magnesium Hardness as $CaCO_3$, ppm	40.0
Sulfite as SO_3, ppm	-
Total Phosphate as PO_4, ppm	-
Orthophosphate as PO_4, ppm	-
Iron as Fe, ppm	-
Specific Conductance Micromhos	230.0
Specific Conductance Micromhos (corrected)	-
Organic	-
	Colorless and Clear

*Sample Taken by Garratt-Callahan Company on October 13, 1976.



PRELIMINARY

TITLE: WATER BALANCE DIAGRAM

PROJECT: 3MW BIOMASS-FIRED COGEN. PLT.

MADE FOR: FLODIN LUMBER AND MANFACTURING
THOMPSON FALLS, MONTANA

GENERAL ELECTRIC
PROJECTS ENGINEERING OPERATION
ENGINEERING SERVICES & PROJECTS DEPARTMENT
ATLANTA, GEORGIA U.S.A.

PRO IDENT. NO.	DWG. NO.	SH.	REV.
40X3011B	M204	CONT. ON SH.	A

DRAWN BY: S.L. White, Jr.

REV. SYMBOLS
AC- APPROVED FOR CONSTRUCTION
PA- FOR APPROVAL
B - BID PURPOSES
P - PRELIMINARY
R - RECORD

REVISION

NO.	SYM.	DATE
A	P	4-28-83

BRUNING 44-141 57122

The makeup to the cooling tower of 94 GPM is to compensate for losses in the closed cooling water system due to evaporation, drift and blowdown. A makeup demineralizer is utilized to obtain suitable boiler quality water.

Geotechnical

Since a soils analysis of the site was not available, only tentative conclusions can be drawn. From visual inspection, the site is relatively level and devoid of obstruction. According to the owners, the sawmill and surrounding area rests on a gravel base approximately fifty feet deep.

From this limited information, pilings are probably not required for equipment and building foundations. For the purposes of this study, spread footings are the only deep foundation type required.

6.2 Environmental

6.2.1 Quality Control

At present, the Sanders County area is classified by the Environmental Protection Agency (EPA) as a Class II region. The applicable emission standards for this region as stated in the Quality Rules of the Montana Department of Health and Environmental Sciences, Environmental Management Commission (Title 16, Chapter 8, Subchapter 14 of the Administrative Rules of Montana) are outlined below:

For particulate emission,

"Q" Heat Input In Million BTU/Hour	"E" Maximum Allowable Emission of Particulate Matter in Lbs/Million BTU
up to and including 10	0.60
100	0.35
1,000	0.20
10,000	0.12

For a heat input between two consecutive heat inputs stated in the preceding table, maximum allowable particulate atter shall be calculated by the equation below:

$$E + 1.0 \text{ X } Q^{-0.2230}$$

Where Q - heat input of fuel burning equipment in million BTU/hr

E - Maximum allowable emission of fly ash and/or other particulate matter in lb per million BTU heat input.

Sulfur Dioxide emissions caused by the combustion of fuel or fuels to be discharged from any stack or chimney shall not exceed one lb. of sulfur per million BTU input.

Since there is an insignificant amount of sulfur dioxide emissions brought about by the combustion of wood/wood waste fuels, there is no need for a flue gas desulfurization system to limit the SO_2 emissions as would be the case with burning "noncompliance" high sulfur coal or even high sulfur fuel oil.

To keep the particulate emissions within the stated limits for the proposed boiler, a high efficiency mechanical collector should be sufficient.

New wood fired boiler installations must also conform to the Prevention of Serious Deterioration (PSD) of air quality, 40 CRF 52 Protection of Environment, if the boiler firing rate exceeds 250 million BTU/Hr or the total of any type pollutant (i.e., particulate, NO_x, SO emitted during a year exceeds 250 tons.

An installation which falls into this category is termed a "major stationary source" or "affected facility" and is also subject to the more stringent New Source Performance Standards promulgated in 40 CFR 60.

The boiler firing rate at full load is appropriately 70 million BTU/HR. Therefore, the maximum allowable particulate emission is calculated below

$$E = 1.0 \times (70)^{-0.2230} = 0.388 \text{ lb/MMBTU}$$

Assuming worst case situation (full load operation for 8000 hr/year).

$$\text{Annual Particulate Stack Emission} = 70 \text{ MMBTU/HR} \times 0.388 \text{ lb/MMBTU} \times 8000 \text{ hr/year}$$

$$= 217{,}280 \text{ lbs or } 109 \text{ tons/year}$$

Based on the worst case scenario, the new boiler would not be classified as a "major stationary source," so would not be subject to New Source Performance Standards.

6.2.2 Water Quality/Usage

As previously discussed, the cogeneration facility, as envisioned, would use a closed cooling water system and a condensate return system. Water usage and discharge, therefore, would be small. In the way of water usages, a single intake or supply point is required for cycle make-up and cooling tower make-up.

Very little effluent would be discharged from the facility and this would consist of "disposable" quality water without undesirable chemical contaminates. Waste water will be produced from:

- Cooling Tower Blowdown
- Boiler Blowdown
- Water Treatment Regeneration Water (depending on water treatment required).

In all cases, water will be suitable (or made suitable by means of simple treatment) to allow disposal locally. The requirements of the Montana Department of Health and Environmental Sciences have been investigated and do not appear to pose any restrictions or requirements that cannot be met with conventional or normal treatment of the plant effluent.

The Clark Fork adjacent to the site is designated by the Montana Department of Health and Environmental Sciences as having a water quality classification of B-1. As such, it is subject to the Water Quality Standards given in the Administrative Rules of Montana entitled "Surface Water Quality Standards," Title 16, Chapter 20, paragraph 16.20.618. The specific requirements which pertain to the discharge of blowdown from the facility are water temperature and pH as stated below.

> A 1°F maximum increase above naturally occurring water temperature is allowed within the range of 32° F to 66° F; within the naturally occurring range of 66° F to 66.5° F, no discharge is allowed which will cause the water temperature to exceed 67° F; and where the naturally occurring water temperature is 66.5° F or greater, the maximum allowable increase in water temperature is 66.5° F or greater, the maximum allowable increase in water temperature is 0.5°F.
>
> Induced variation of hydrogen concentration (pH) within the range of 6.5 to 8.5 must be less than 0.5 pH unit. Natural pH outside this range must be maintained without change. Natural pH above 7.0 must be maintained above 7.0.

Discharge of waste water to the Clark Fork will be monitored to assure conformance to the standards.

6.2.3 Noise

Contribution of additional noise by the cogeneration plant would not violate noise standards. Judicious design of the plant can ensure compliance with OSHA standards for protection of operating personnel from noise exposure.

6.2.4 Solid Waste Management

Ash generated from burning sawmill wood waste in the existing power boilers and teepee burners is disposed of onsite at the company owned landfill.

This method would continue to be used after the cogeneration plant begins operation.

6.3 SCHEDULING

The schedule for building a biomass fired cogeneration plant of the type described herein is estimated at 24 months. The schedule can be divided into four broad phases.

°Environmental Review and Permitting - 6-10 months
°Conceptual Engineering and Equipment Procurement - 4-6 months
°Detailed Engineering/Design and Equipment Delivery - 12 months
°Construction Including Erection and Startup - 12 months

A further breakdown of the major project activities are depicted in a bar chart graph in figure 6-1. Equipment deliveries currently quoted by manufacturers are 12 months on the boiler and 14-16 months on the turbine generator after placement of the purchase order. A used turbine-generator will be purchased instead, so the cycle time for removal, transportation and refurbishment would not exceed 12 months.

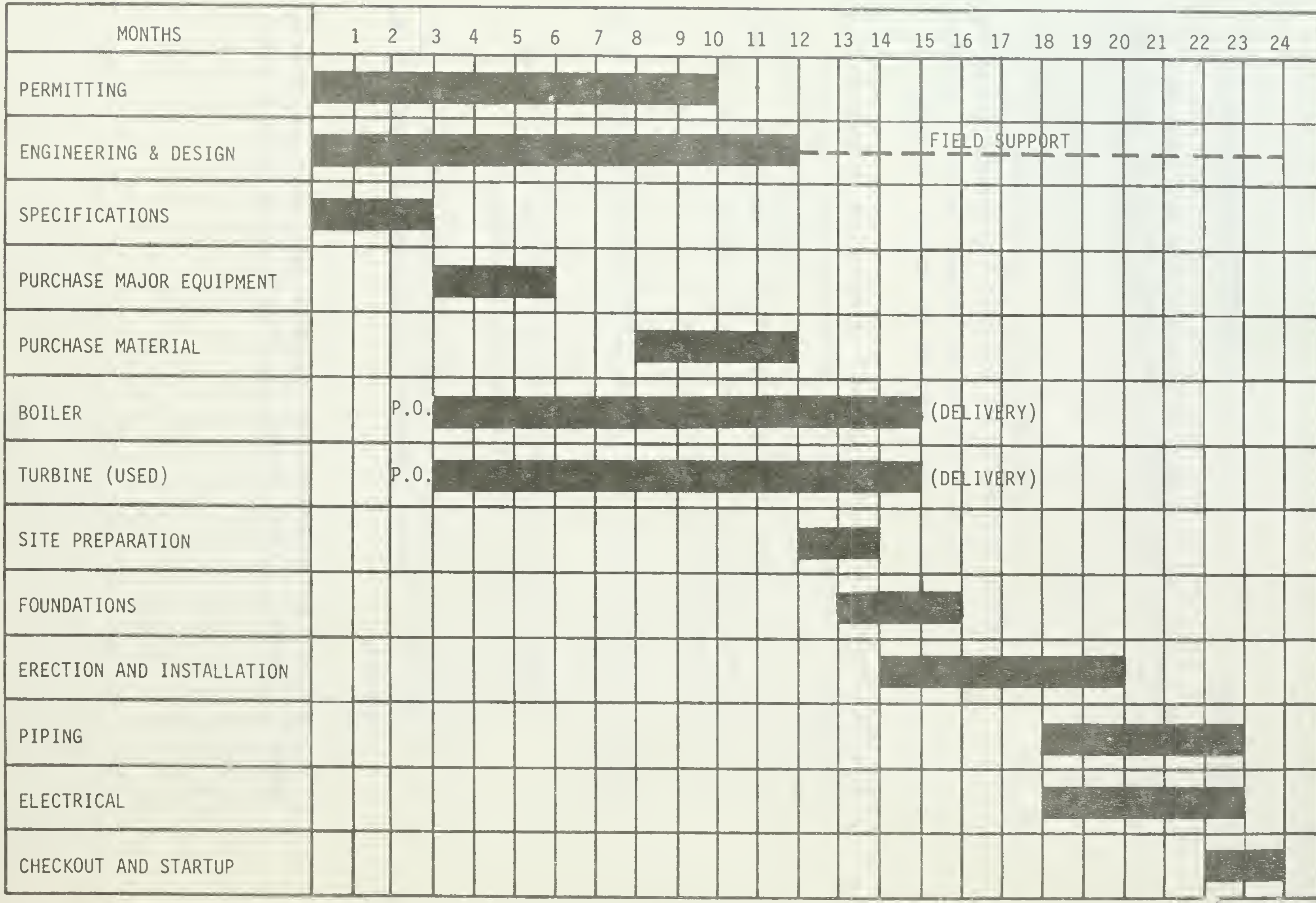
The total project duration of 24 months is readily achievable based on the following premises:

° Purchase orders be placed as soon as possible on long delivery equipment such as the boiler and turbine-generator.

° Engineering and design and equipment procurement be performed in parallel with the environmental review and permitting phase of the project.

If no commitments can be made on major equipment until after the permitting process is complete, a total schedule exceeding 30 months can be expected.

PROJECT SCHEDULE



6.4 PERMITTING

Prior to the construction and/or operation of an industrial facility in Montana, certain permits are required by federal, state or local regulatory agencies. Jurisdiction of Federal Air and Water Quality Standards in Montana has transferred from the U.S. Environmental Protection Agency to the State of Montana, so application for the following permits would be processed, reviewed and approved at the state level.

-Montana Pollutant Discharge Elimination System (MPDES) Permit
-Air Quality Permit

The MPDES permit is required of any owner or operator of any proposed point source discharging pollutants into state waters. A completed MPDES permit application must be filed with the state no less than 180 days prior to operation of the point source. The specific requirements for application are delineated in Paragraph 16.20.904 of the Administrative Rules of Montana on Water Quality.

An Air Quality Permit is required prior to construction, installation, alteration or use of any air contaminent source or stack associated with any source, unless specifically excluded in Paragraph 16.8.1102. The submittal of the air quality permit application differs from the aforementioned in that the application must be made 180 days before construction begins. The permit application requirements are specified in the Montana Air Quality Standards, Paragraph 16.8.1102.

In most localities, a building construction permit will not be issued until the necessary environmental permits have been applied for and issued by the state.

7.0 CONCLUSIONS AND RECOMMENDATIONS

7.1 Conclusions

The addition of a biomass fired cogeneration plant at the Flodin Lumber and Manufacturing Company's sawmill facility is a feasible and economically attractive investment. The supply of wood byproducts from the Flodin Lumber sawmill operation and neighboring sawmills is readily available, inexpensive, and sufficient to support the operation of a 3 1/2 MW cogeneration plant.

The design of the complete cogeneration facility for the burning of wood in a power boiler and the subsequent generation of electricity is a well established and proven technology. The environmental constraints placed on new wood fired boilers installations by Federal and State regulatory authorities are readily achieved by best available control technology without undue expense to the owner.

Legislation enacted by Congress provides numerous incentives at the federal and state level to encourage the companies such as Flodin Lumber to undertake cogeneration projects which typically are highly capital intensive. One such incentive is the investment and energy tax credits granted to qualifying companies to help offset part of the initial capital expenditure. Other legislative incentives ensure that the cogenerator can interconnect with the Utility's grid and sell the electricity generated to the Utility at a fair and just price.

At present, MPC, under mandate of the Montana Public Service Commission, is required to purchase electricity from qualifying cogenerators at 100 percent of the full avoided cost. Based on the long term power purchase schedule currently in effect, the discounted return on investment based on the after-tax cash flow generated from the sale of electricity is 26 percent. This high rate of return may be reduced if either the final capital costs exceed the budgetary estimate or the utility is successful in its appeal to the Public Service Commission to have the rates for power purchase decreased. The sensitivity analysis performed herein shows that the ROI for the cogeneration plant would still be an attractive investment for Flodin Lumber.

Flodin Lumber's alternative to cogeneration is to continue to operate the existing 40-year-old boilers until such time as they need to be replaced with a 125# wood fired packaged boiler. Since replacement of the boilers is inevitable, the addition of a complete cogeneration plant in lieu of a new package boiler would be advantageous, considering the favorable legislation and tax incentives available to cogenerators burning alternate biomass fuels.

7.2 Recommendations

Having received and reviewed the feasibility study content and findings, Flodin Lumber Company has stated concurrence with the recommendations set forth therein. By way of continuing the developmental phase of the biomass to energy program, Flodin has initiated the following project related activities:

° Initiated preliminary discussions with the State of Montana Environmental Regulatory Authorities with view to determining the nature and extent of applicable air, ground and water emission/pollution control mandates attending the inception of the energy generating facility.

° Solicited from the General Electric Company, a firm price and firm schedule bid to engineer and construct the biomass to energy plant. Current plans call for the offering to be delivered for Flodin Lumber Company's review during November of 1983.

° Initiated dialogue with financial institutions with a view to properly determine the financing alternatives available to

Flodin as Owner of the energy generating facility. Said option's include the "trading" of investment and energy tax credits in return for a power implicit interest rate, leveraged leasing, revenue bonding and general obligation bonds and such other innovations as are available to effectively finance the program.

With the above in hand, Flodin Lumber Company will be able to make an intelligent decision relative to proceeding with the project. Current indications are that a decision will be forthcoming during the late '83/early 1984 timeframe.

8.0 APPENDIX

8.1 USED EQUIPMENT

One method of decreasing the initial capital investment which has been used quite successfully is the purchase of used equipment. This equipment is usually available for 1/4 to 1/2 the price of new equipment. Although refurbishment and general tune-up is required in most instances, the net result is usually a significant capital cost savings.

The most important aspect of used equipment purchase is the search and selection of the potential equipment and its "serviceability" assessment by knowledgeable craftsmen. If this function is performed correctly, the result is equipment that will perform the function intended for many years at significant cost savings.

Many reputable dealers are available and willing to advise what type of equipment is available and will also provide a "history" on each piece. Equipment which may be successfully purchased in this manner includes:

Steam Turbine/Generator and Auxiliaries
Power Boiler and its Auxiliaries

For the purpose of this study, only the steam turbine generator and associated auxiliaries are explored. The feasibility of utilizing a used power boiler is ordinarily limited to packaged units. In very few instances, used field erected boilers may be considered depending on such factors as the proximity of the existing boiler to the job site and the type of boiler construction (i.e. modular construction lends itself more to disassembly and relocation).

Table 8-1 gives a listing and description of several used turbines which are presently available for purchase. The turbine generator which best fits the cycle requirements of the new facility is Item 2 on the list.

NOTE: The installation impact of used equipment must be reviewed prior to purchase. For example, the installation cost of a used turbine should be the same as a new unit plus the removal of the used turbine cost. The installation costs of a field-erected boiler will be higher than that of a new unit, in addition, the removal costs will be quite high.

TABLE 8-1
USED STEAM TURBINE GENERATORS

1. 1 - 3000 KW 80 percent PF 3750 KVA General Electric generator, 3 phase, 60 cycle, 13,200 volts, 3600 RPM, direct connect to

   1 - 3000 KW General Electric condensing turbine, 600# steam pressure, 800 F, 3600 RPM.
   Turbine equipped with condenser.

****

2. 1 - 3500 KW 80 percent PF 4375 KVA General Electric Generator, 3 phase, 60 cycle, 2400 volts, 3600 RPM, direct connected to

   1 - 3500 KW General Electric condensing extraction turbine, 600# steam pressure, 55# extraction, Form GG, 3600 RPM.

   New 1945. Rebuilt 1967.

3. 3 - 5000 KW 80 percent PF 6250 KVA General Electric generators, 3 phase, 60 cycle, 11,500 volts, Type ATB-2, 3600 RPM, directed connected to

   3 - 5000 KW General Electric condensing double extraction turbines, 540# steam pressure, 700 F, with automatic extractions at 150# and 50#, Form JJ, 3600 RPM.
   Generator equipped with exciters.
   Turbines equipped with Allis Chalmers surface condensers.

   New 1942.

4. 1 - 5000 KW 80 percent PF 6250 KVA General Electric generator, Type ATB, 3 phase, 60 cycle, 2400/5160 volts, 3600 RPM, direct connected to

   1 - 5000 KW General Electric condensing turbine, 400# steam pressure, 750 F, 15 stage, 3600 RPM.

****

5. 1 - 7500 KW 80% PF 9375 KVA General Electric generator, 3 phase, 60 cycle, 13,200 volts, 3600 RPM, direct connected to

   1 - 7500 KW General Electric condensing turbine, 400# steam pressure, 750 F, 16 stage, 3600 RPM.

   New 1950.

8.2 ASSUMPTIONS

1. Plant operation for sawmill is 16 hrs/day, 5 days/week, with 11 holidays a year. The cogeneration plant is assumed to operate 8000 hr/yr.

2. The operating personnel for the new cogeneration plant will be the same as for the existing boiler plant, i.e. 4 operators, 1 per shift and one swing.

3. The customer's minimum acceptable rate of return (MARR) is 10-12 percent.

4. Plant life for the purposes of this study is assumed to be 15 years.

5. Insurance premiums are 53¢ per $100 of insured property.

6. The current property tax rate is estimated at 1 percent of market value.

7. Capital costs for the proposed plant are in 1983 dollars.

8. Interest during construction is not considered in the economic analysis.

9. Operating expenses and revenues from electrical sales is assumed to escalate at 6 percent annually.

10. Financing for the project is assumed to be 100 percent of the capital cost at 12 percent APR for a term of 15 years.

11. Fuel costs for wood byproducts from the sawmill operation are assumed as $2.50/unit of hogged fuel, $2.50/unit of sawdust and $5.00/unit of shavings.

12. It is assumed the Flodin Lumber can take advantage of the available tax credits for the cogeneration plant investment to offset the tax liability on profit from the sawmill operation.

8.3 REFERENCES

1. Guidelines for the Interfacing of Co-Generators and Small Power Producers with the Montana Power Company System, May 1982.

2. "In the Matter of Avoided Cost Based Rates for Public Utility Purchases from Qualifying Cogenerators and Small Power Producers," Dept. of Public Service Regulation Before the Public Service Commission of the State of Montana, Utility Division Docket No. 81,2,15, Order No. 4865.

3. Administrative Rules of Montana, Title 16, Chapter 20, "Water Quality," Montana Department of Health and Environmental Sciences.

4. Administrative Rules of Montana, Title 16, Chapter 8, "Air Quality," Montana Department of Health and Environmental Sciences.

5. Wood Combustion Principles, Processes and Economics, David Tillman, Amadea J. Rossi, William Kitto, Academic Press 1981

6. Feasibility Study for a Forest-Residue - Fueled Electric Generating Plant, EPRI CS-1819, TPS 79-742, May 1981

7. Federal Energy Regulatory Commission (FERC) Order No. 69, Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Act of 1978, issued Feb. 19, 1980.

8. Protection of Environment, 40 CFR 52 & 60

9. Montana Renewable Energy Program, "1982 Guidelines for Preparing Grant and Loan Proposals," Montana Department of National Resources and Conservation.

Agreement

Cogeneration

and

Small Power Production

Power Purchase Agreement

Between

____

and

The Montana Power Company

Index

Appendix A

General Contract Terms and Conditions

A-1 Definitions

As used in this Agreement and the Appendices and Schedules attached hereto, the following terms shall have the following meanings:

a. "Annual Capacity Factor" - The ratio, expressed as a percentage, of the actual Energy output of a generating unit over a period of one year to the product of Capacity and 8,760 hours; or if the period for which Capacity Factor is to be determined is less than one year, it will be the ratio of actual Energy output during the period to the product of Capacity and the number of hours in the period.

b. "Annual Capacity Payment Adjustment" - The procedure performed at the end of each Contract Year for Sellers under the Long-Term Power Purchase tariff provision which reconciles payments made by Company to Seller during the Contract Year based upon estimated Capacity and Capacity Factor with payments that would have been made had they been based on actual Capacity and Annual Capacity Factor.

c. "Associated Energy" - The amount of Energy expressed in kilowatthours provided to Company by Seller in conjunction with the supply of Capacity under Article 3 of this Agreement.

Article 1

Term of Agreement

This Agreement shall be binding upon execution and shall remain in effect for a term consisting of the first partial year from the effective date of this contract until the June 30 immediately following such effective date and an additional period of ________ ________________ from said June 30.

Article 2

Sale of Power

a. Seller agrees to sell and deliver and Company agrees to purchase and accept delivery of Energy or Capacity and Associated Energy, subject to terms and conditions hereinafter set forth, in accordance with this Agreement and applicable Montana Public Service Commission approved rate schedules in effect. If Seller is a supplier of Capacity and Associated Energy hereunder, Seller hereby commits to a Contract Capacity of ____________ kW at an estimated Annual Capacity Factor in the initial Contract Year of ________%, subject to adjustment based on demonstrated Capacity and Annual Capacity Factor at the end of each Contract Year, and hereby affirms that this amount is no greater than the Capacity Rating of Seller's Facility.

Seller elects, for purposes of computing payments hereunder, to supply Energy or Capacity and Associated Energy to Company in accordance with one of the following tariff and billing options:

1. Short-Term Power Purchase

   _______ a. Standard Payment

   _______ b. Net Billing Option

2. Long-Term Power Purchase

   _______ a. Standard Payment

   _______ b. Net Billing Option

(Seller to initial one option only under either Category 1 or Category 2 above.)

If Seller selects Long-Term Power Purchase option, then Contract Capacity and estimated Annual Capacity Factor must be specified.

Article 3

Purchase Price and Method of Payment

a. Energy

Company shall pay Seller for Energy delivered and accepted in accordance with the applicable Montana Public Service Commission approved rate schedule in effect for the period during which such deliveries are made.

b. <u>Capacity and Associated Energy</u>

If Seller elects to supply Capacity and Associated Energy, Company shall pay Seller for Capacity in accordance with the applicable Montana Public Service Commission approved rate schedule in effect for the period during which such deliveries are made. Company's obligation to pay Seller for Capacity and Associated Energy furnished to Company shall commence as of the Operation Date.

c. <u>Payments</u>

Company shall make payments to Seller for deliveries in accordance with terms and conditions of this Agreement at the address of Seller specified in Article 4 hereof within 20 days after the monthly meter readings have been accomplished to determine the amount of net deliveries or direct deliveries into the system of Company from Seller during the billing period. Seller shall pay Company for Company's costs incurred hereunder or for Annual Capacity Payment Adjustment, at the address specified for Company in Article 4, in accordance with payment provisions specified hereunder or in accordance with Company's written statement. Should either Party fail to pay the other Party in full the charges reflected in such statements within the time allotted, the unpaid Party may deduct like amounts, adjusted for costs associated with short-term borrowings of the unpaid Party, from future payments to the other Party hereunder.

Article 4

Notices

All written notices under this Agreement shall be directed as follows, and shall be considered delivered when deposited in the US Mail, first class postage prepaid, as follows:

To Seller: ______________________________
____
____
____
____

To Company: Vice President, Operations
The Montana Power Company
40 East Broadway
Butte, MT 59701

Article 5

Electric Services Supplied by Company

This Agreement does not provide for any electric services by Company to Seller. If Seller requires any services from Company, Seller shall receive such service in accordance with Company's applicable electric tariffs on file with and authorized by the Montana Public Service Commission, and the Company may require as a condition of such service that Seller execute a separate agreement covering the sale of power by the Company to the Seller at the point of delivery defined herein.

Article 6

Force Majeure

The term "Force Majeure" as used herein, means unforeseeable causes beyond the reasonable control of and without fault or negligence of the Party claiming Force Majeure.

If either Party because of Force Majeure is rendered wholly or partly unable to perform its obligations under this Agreement, except for the obligation to make payments of money, that Party shall be excused from whatever performance is affected by the Force Majeure to the extent so affected provided that:

1. the non-performing Party, within two weeks after the occurrence of the Force Majeure, gives the other Party written notice describing the particulars of the condition or occurrence which resulted in the Force Majeure;

2. the suspension of performance is of no greater scope nor of longer duration than is required by the Force Majeure;

3. obligations of either Party which arose before the occurrence causing the suspension of performance are not excused as a result of the occurrence of Force Majeure; and

4. the non-performing Party uses its best efforts to remedy its inability to perform. This subparagraph shall not require the settlement of any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to its interest. It is understood and agreed that the settlement of strikes, walkouts, lockouts or other labor disputes shall be entirely within the discretion of the Party having difficulty.

Article 7

Indemnity

Each Party shall indemnify the other Party, its officers, agents, and employees against all loss, damage, expense and liability to third persons for injury to or death of person or injury to property, proximately caused by the indemnifying Party's construction, ownership, operation, or maintenance of, or by failure of, any of such Party's works or facilities used in connection with this Agreement. The indemnifying Party shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party shall pay all costs that may be incurred by the other Party in enforcing this indemnity.

Article 8

Liability and Insurance

a. Seller agrees to protect, indemnify and hold harmless Company, its directors, officers, employees, agents, and representatives, against and from any and all loss, claims, actions, or suits, including costs and attorneys' fees, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction of property belonging to Company or others, resulting from, or arising out of or in anyway connected with the facilities on Seller's side of the Point of Delivery, or Seller's operation and/or maintenance, excepting only such injury or harm as may be caused solely by the fault or negligence of Company, its directors, officers, employees, agents or representatives.

b. Prior to connection of Seller's generation equipment to Company's system, Seller shall secure and continuously carry in an insurance company or companies acceptable to Company comprehensive general liability, bodily injury and property damage insurance.

Such insurance shall include provisions that such policies shall not be cancelled or their limits of liability reduced without thirty (30) days' prior written notice to Company. A copy of each such insurance policy, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of Company in lieu thereof, a certificate in form satisfactory to Company certifying to the issuance of such insurance, shall be furnished to Company. Initial limits of liability for all requirements under this Section (B) shall be $_________ single limit, which limit may be required to be increased with good cause by Company's giving Seller ninety (90) days' notice.

c. In the event that Seller agrees to make Contract Capacity and Associated Energy sales to Company, Seller agrees to obtain insurance acceptable to Company against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller shall promptly notify Company of any loss or damage to the Facility. Unless the parties agree otherwise, Seller shall repair or replace the damaged or destroyed Facility.

Article 9

Liability; Dedication

Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to or any liability to any person not a Party to this Agreement.

No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of Company as an independent public utility corporation, or Seller as an individual or entity.

Article 10

Several Obligations

Except where specifically stated in this Agreement to be otherwise, the duties, obligations and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership, or joint venture or impose a trust or partnership duty, obligation or liability on or with regard to either Party. Each Party shall be individually and severally liable for its own obligations under this Agreement.

Article 11

Waiver

Any waiver at any time by either Party of its rights with respect to a default under this Agreement, or with respect to any other matters arising in connection with this Agreement, shall be made in writing. Such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

Article 12

Assignment & Ownership

a. Neither Party shall voluntarily assign its rights nor delegate its duties under this Agreement, or any part of such rights or duties, without the written consent of the other Party, except in connection with the sale or merger of a substantial portion of its properties including Interconnection Facilities which it owns, and any such assignment or delegation made without such written consent shall be null and void. Consent for assignment will not be withheld unreasonably.

b. Energy and Capacity delivered to Company under this Agreement shall become the property of the Company at the Point of Interconnection and as such subject to the exclusive use of the Company for any purpose considered appropriate in its sole discretion.

Article 13

Choice of Laws

This Agreement shall be construed and interpreted in accordance with the laws of the State of Montana, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

Article 14

Governmental Jurisdiction and Authorization

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. This Agreement shall not become effective until all required governmental authorizations and permits are first obtained and copies thereof are submitted to Company; provided, that this Agreement shall not become effective unless it, and all provisions thereof, is authorized and permitted by such governmental agencies without change or condition.

This Agreement shall at all times be subject to such changes by such governmental agencies, and the Parties shall be subject to such conditions and obligations, as such governmental agencies may, from time to time, direct in the exercise of their jurisdiction. Both Parties agree to exert their best efforts to comply with all applicable rules and regulations of all governmental agencies having control over either Party or this Agreement. The Parties shall take all reasonable action necessary to secure all required governmental approval of this Agreement in its entirety and without change.

Article 15

Captions

All indexes, titles, subject headings, section titles and similar items are provided for the purpose of reference and convenience and are not intended to be inclusive, definitive or to affect the meaning of the contents or scope of this Agreement.

Article 16

Modification

No modification of this Agreement shall be valid unless it is in writing and signed by both Parties hereto.

Article 17

Terms and Conditions

This Agreement includes applicable Montana Public Service Commission approved rate schedules currently in effect and Appendix A - General Contract Terms and Conditions, which are attached and incorporated by reference herein.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the last date hereinabove set forth:

SELLER	THE MONTANA POWER COMPANY
BY: ______________________	BY: ______________________
______________________ (Type Name)	______________________ (Type Name)
TITLE: ______________________	TITLE: ______________________

Appendix A

General Contract Terms and Conditions

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Appendix A

General Contract Terms and Conditions

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b. "Annual Capacity Payment Adjustment" - The procedure performed at the end of each Contract Year for Sellers under the Long-Term Power Purchase tariff provision which reconciles payments made by Company to Seller during the Contract Year based upon estimated Capacity and Capacity Factor with payments that would have been made had they been based on actual Capacity and Annual Capacity Factor.

c. "Associated Energy" - The amount of Energy expressed in kilowatthours provided to Company by Seller in conjunction with the supply of Capacity under Article 3 of this Agreement.

d. "Avoided Energy Cost" - The cost Company would have incurred for Energy supplies in the absence of Energy supplies available to Company from Seller's Facility.

e. "Avoided Capacity Cost" - The cost Company would have incurred for Capacity in the absence of Capacity supplied to Company by Seller.

f. "Capacity" - The maximum net amount of electric power the Facility generates and delivers to Company at the high-voltage bus of the Company at the site of Facility, expressed in kilowatts (kW).

g. "Capacity Rating" - The magnitude of Capacity Seller's Facility is capable of supplying.

h. "Contract Capacity" - The amount of Capacity in kilowatts (kW) which Seller commits to supply to Company under Article 3 of this Agreement.

i. "Early Contract Termination" - The early termination of this Agreement.

j. "Contract Year" - A twelve month period of time commencing immediately after midnight on July 1 of any year and ending at midnight on June 30 of the following year.

k. "Energy" - Electric energy supplied by Seller expressed in kilowatthours (kWh).

l. "Facility" - That generation facility operated by Seller, and subject of this Agreement.

m. "Force Majeure" - As defined in Article 6 of this Agreement.

n. "Interconnection Equipment" - All equipment required to be installed solely to interconnect and accommodate delivery of power from Seller's generation Facility to Company's system including, but not limited to connection, transformation, switching, metering and safety equipment. Interconnection Equipment shall also include any necessary additions and/or modifications by Company to its system.

o. "Long-Term Power Purchase" - The tariff provision which applies to the production of a Seller who contracts to supply power to Company for a period of not less than four years.

p. "Net Billing" - The optional billing arrangement under this Agreement which uses the net production of the Seller (monthly production minus monthly consumption where two meters are used; total reduction of "consumption" registration from previous billing period where only one meter is used), if any, during any billing month, which net production serves as the bases for payment to Seller by Company in accordance with applicable rate schedules. If consumption during the month exceeds production, then Seller is billed for net consumption at the applicable retail rate.

q. "Operation Date" - The day commencing at 12:01 am, following the day during which all features and equipment of Facility have reached a degree of completion and reliability, such that they are capable of operating simultaneously to produce power.

r. "Point of Delivery" - The location at which the electrical facilities of Seller and Company are connected.

s. "Prudent Electrical Practice" - Those practices, methods and equipment, as changed from time to time, that are commonly used in prudent electrical engineering and operations to operate electrical equipment lawfully and with safety, dependability, efficiency and economy.

t. "Seller's Property" - Facility and all Interconnection Equipment belonging to Seller.

u. "Short-Term Power Purchase" - The tariff provision which applies to the production of a Seller who contracts to supply power to Company for a period of not less than one year.

v. "Special Facilities" - Interconnection Equipment furnished by Company at Seller's request and expense, and other Company system additions or modifications required to accommodate deliveries from Facility to Company's system, also installed, operated and maintained at the expense of Seller.

A-2 Construction

a. Land Rights

Seller hereby grants to Company for the term of this Agreement, and for such reasonable time thereafter as may be required to remove the Company's property, all necessary rights-of-way and easements to install, operate, maintain, replace and remove metering and other Special Facilities, including adequate and continuing access rights on property of Seller; and Seller agrees to execute such other grants, deeds or documents as Company may require to enable it to record such rights-of-way and easements. If any part of Company's facilities are to be installed on property owned by other than Seller, Seller shall, if Company is unable to do so without cost to Company, procure from the owners thereof, all necessary permanent rights-of-way and easements for the construction, operation, maintenance and replacement of Company's facilities upon such property in a form satisfactory to Company. At Seller's request and sole expense, Company shall, to the extent it is legally able, acquire necessary rights-of-way at such cost as may be agreeable to Seller.

b. Facility and Equipment Design and Construction

Seller shall design, construct, install, own, operate and maintain the Facility and all equipment needed to generate and deliver Energy or Capacity and Associated Energy specified herein, except for any Special Facilities constructed, installed and maintained by Company for Seller's benefit, which such

Special Facilities shall be installed, operated and maintained at the expense of Seller. Such Facility and equipment shall meet all requirements of applicable codes and all standards of Prudent Electrical Practice. Seller also agrees to meet reasonable Company requirements for Seller's Facility and equipment. Seller shall submit all its Facility and equipment specifications to Company for review prior to connecting its Facility and equipment to Company's system. Company's review of Seller's specifications shall not be construed as confirming nor endorsing the design nor as any warranty of safety, durability or reliability of the Facility or any of the equipment. Company shall not, by any reason of such review or failure to review, be responsible for strength, details of design, adequacy or capacity, successful operation or performance of Seller's Facility or equipment, nor shall Company's acceptance be deemed to be an endorsement of any Facility or equipment. Seller agrees to change its Facility and equipment as may be reasonably required by Company to meet changing requirements for construction, design, or operation of Company's system, and to make such required changes at Seller's expense. All changes in specifications, including new or additional equipment shall also be subject to Company's acceptance and approval as provided above. Seller shall interconnect its Facility with equipment of Company only after it has received from Company written acceptance of all Facility specifications and after it has received and complied with written requirements from Company for such interconnection.

c. Interconnection Equipment

Seller shall construct, install, own and maintain Interconnection Equipment as required for Company to receive Energy or Capacity and Associated Energy from Seller's Facility. Seller's Interconnection Equipment shall be of sufficent size and capability to accommodate the delivery of Energy or Capacity and Associated Energy under this Agreement. Seller shall allow Company to review the characteristics and specifications of all protective devices, and to establish requirements for protective equipment ratings and settings and periodic testing; provided, however, that neither such review nor the lack of such review by Company shall be construed as a warranty or endorsement of the safety, adequacy, or performance of Seller's Interconnection Equipment. In the event it is necessary for Company to install Special Facilities or other Interconnection Equipment or to alter its system for purposes of this Agreement, Seller shall reimburse Company for all of its costs associated therewith, including annual costs associated with ownership, operation and maintenance; provided, however, that Seller will be provided with an estimate of all such costs and must approve of all such costs before required work by Company may begin; and provided further that arrangements for method and timing of payments to be made by Seller to Company for such costs will be mutually agreed upon among the Parties in advance of the time construction by Company is to begin.

A-3 Metering

a. If Seller elects to receive payment under the Standard Payment Option appropriate metering equipment capable of accurately measuring and recording or indicating flow of Energy in kilowatthours, integrated demand for each hour if required, and, at the option of Company, reactive volt-ampere hour flow between Seller's Facility and Company's system, will be furnished and installed by the Company at the expense of Seller at a mutually agreeable location. Company may also in its sole discretion, install secondary meters at a mutually agreeable location within Seller's Facility for the purpose of enabling Seller to make telephone reports to Company as may be required. The location of metering equipment shall not necessarily signify location of division of ownership of facilities or Point of Delivery. Company shall own, maintain and test meters. All costs associated with the purchase, installation, ownership, maintenance, inspection and periodic testing of meters, and related administrative costs incurred by Company in metering Seller's generation shall be borne by Seller.

A-4 Operation

a. Facility and Equipment Operations and Maintenance

Seller's Property shall meet the requirements of all applicable State and Local Laws. Prior to commencement of generation and interconnection of Seller's Facility with the system of the Company, Seller's Property shall be inspected and approved by the appropriate State and Local officials. Seller shall operate and maintain Facility in a safe manner and in accordance with the National Electrical Safety Code.

Seller's Property shall include the following equipment to be installed, operated, and maintained in good working order by Seller:

1. A lockable main disconnect switch which allows isolation of Seller's Facility from Company's system. Such disconnect switch will be located by mutual agreement of the Parties, and at all times will be accessable to and operable by qualified employees or agents of Company as well as Seller.

2. An automatic disconnecting device which is designed to operate in conjunction with and in response to appropriate relays and protective devices.

3. Relays and controls required by Company.

4. Equipment as required to establish and maintain Facility generation operation in synchronism with Company's system.

Seller shall operate and maintain its Facility and equipment according to Prudent Electrical Practices; the instantaneous reactive power consumed from the Company shall not exceed thirty-two percent (32%) of the real power being generated by the Facility; and the instantaneous reactive power delivered to the Company shall not exceed thirty-two percent (32%) of the real power being generated by the Facility. In the absence of compliance by the Seller with the above reactive power restrictions, then Company may, without incurring liability, disconnect Seller's Facility from Company's system. During such period of disconnection, Company's obligation to make payments to Seller shall be suspended.

If conditions on Company's system require, in the sole determination of Company, a change in Company's system voltage at the Point of Delivery, Company will give no less than one hundred eighty (180) days notice to Seller of such change, and, at the expiration of the notice period, may make the required voltage change and require Seller to make necessary modifications to Seller's Interconnection Equipment, at Company's expense, to maintain compatibility with Company's modified system operating voltage level. If mutually agreed between Seller and Company, Company may make necessary modifications to Seller's Interconnection Equipment, also at Company's expense.

b. <u>Distortions</u>

Seller shall remedy any harmonic distortion on Company's system attributable to the operation of Seller's Facility which may result in objectionable service to Company's other customers. If Seller's actions to remedy such harmonic distortions prove inadequate, then Company may, without incurring liability, disconnect Seller's Facility from Company's System. During such occasions when the meters are to be inspected, tested, adjusted or reset.

Company shall, at Seller's expense, inspect and test all meters supplied at Seller's expense upon their installation and at least once every two years thereafter. If requested to do so by Seller, Company shall inspect or test such meter more frequently than every two years, but the expense of such inspection or test shall be paid by Seller unless, upon being inspected or tested, such meter is found to register inaccurately by more than two percent of full scale, in which case the expense of testing will be borne by Company. Each Party shall give reasonable notice to the other Party of the time when any inspection or test shall take place, and that Party may have representatives present at the test or inspection. If such meter is found to be inaccurate or defective, it shall be adjusted, repaired or replaced, at Seller's expense, in order to provide accurate metering.

If any meter (Company supplied or Seller supplied) fails to register, or if the measurement made by a meter during a test varies by more than two percent from the measurement made by the standard meter used in the test, appropriate adjustment shall be made correcting all measurements made by the inaccurate meter for:

1. the actual period during which inaccurate measurements were made, if the period can be determined, or, if not,

period of disconnection, Company's obligation to make payments to Seller shall be suspended.

c. Shortages

Seller agrees that, for any period during which the Company determines there is a shortage of supply of Energy or Capacity or both available to its system, Seller will, at Company's request, and within reasonable and safe limits on levels of production as determined by Seller, use its best efforts to provide requested Energy and/or Capacity and Associated Energy, and shall, if necessary, delay any maintenance periods.

d. Deliveries

Seller shall deliver Energy or Capacity and Associated Energy under this Agreement to Company at the Point of Delivery.

e. Communications

Company, through its system dispatcher, or other appropriate operating personnel, and Seller shall maintain operating communications in order to effectively accomplish system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, requirements of Company for operation reports and other operating functions deemed necessary by Company.

f. Meters

All meters used to determine the billing hereunder shall be sealed and the seals shall be broken only by Company upon

2. the period immediately preceding the test of the meter equal to one-half the time from the date of the last previous test of the meter; provided, that the period covered by the correction shall not exceed six months.

Each Party, after giving reasonable notice to the other Party, shall have the right of access to all metering and related records.

g. <u>Delivery Reductions and Interruptions</u>

Company shall not be obligated to accept deliveries from Seller, and may require Seller to interrupt or reduce deliveries of Energy or Capacity and Associated Energy, during periods of emergencies, Forced Outages, occurrence of operating conditions requiring such interruption or reduction as determined by Company, or to allow Company to install, maintain, repair, replace, remove or inspect equipment on any part of Company's system, or as otherwise required by Prudent Electrical Practices.

Except in cases of emergency, where possible, either Party shall give reasonable notice to the other Party of the need to reduce or interrupt deliveries to Company from Seller's Facility, and with such notice the reason the reduction or interruption is required, and the probable duration of the condition or circumstance requiring such interruption or reduction.

In the event of a Force Majeure affecting the ability of either Party to perform as required by this Agreement, Seller shall not be obligated to deliver, and may curtail, interrupt or reduce deliveries of Energy or Capacity and Associated Energy to Company, and Company shall not be obligated to accept and may require Seller to curtail, interrupt or reduce deliveries of Energy or Capacity and Associated Energy.

h. Scheduling

Prior to December 31 of each year, Seller shall prepare in writing and send to Company a proposed schedule of generation for each month of the ensuing eighteen (18) months beginning with January of the following year. Said schedule shall indicate the estimated times of operation, estimated amounts of production, anticipated shutdowns and scheduled maintenance periods.

i. Monthly Statements

Within 20 days following the end of each monthly billing period, Company shall send a statement to Seller showing the amount of Energy or Capacity and Associated Energy delivered to Company's system during the billing period, if any, the amount due Seller from Company in accordance with applicable Contract provisions and rate schedules, and a check for the amount due Seller for such billing period.

j. Adjustments

In the event adjustments to statements are required as a result of corrected measurements made by inaccurate meters, the Parties shall use the corrected measurements described in Article 9(f) to recompute the amounts due from or to Company for the Energy or Capacity and Associated Energy delivered under this Agreement during the period of inaccuracy. If the total amount, as recomputed, due from a Party for the period of inaccuracy varies from the total amount due as previously computed, and payment of the previously computed amount has been made, the difference in the amounts shall be paid to the Party entitled to it within 30 days after the paying Party is notified of the recomputation.

k. Changes in Capacity Rating

The Capacity Rating of Seller's Facility (if applicable) under Article 3(a) is subject to change if for any reason the assured Capacity capability of Facility changes or is proven to be different than the amount indicated in Article 3(a). If Capacity capability changes or if Capacity capability is proven different, a new Capacity Rating and Contract Capacity amount shall be established for Facility, and such new amount shall be used for purposes of this Agreement in the place of the Contract Capacity amount originally indicated in Article 3(a).

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